

Northern Territory Electricity Outlook Report 2020



Disclaimer

The Northern Territory Electricity Outlook Report (NTEOR) is prepared using information sourced from participants of the electricity supply industry, Northern Territory Government agencies, consultant reports and publicly available information. The NTEOR is in respect of the financial year ending 30 June 2020. The Utilities Commission understands the information received to be current as at October 2020.

The NTEOR contains analysis and statements based on the Commission and Australian Energy Market Operator's interpretation of data provided by Territory electricity industry participants. The Commission has sought to align its reporting of data with the other Australian jurisdictions where possible, to enable comparison. However, there are some differences, therefore any comparisons should only be considered indicative.

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Any questions regarding this report should be directed to the Utilities Commission utilities.commission@nt.gov.au or by phone 08 8999 5480.

About this report

Since 2018, the Utilities Commission of the Northern Territory (Commission) has published an annual Northern Territory Electricity Outlook Report (NTEOR), which focuses on the system demand and supply outlook for the Darwin-Katherine, Alice Springs and Tennant Creek power systems (regulated power systems).

This 2020 NTEOR presents electricity consumption, maximum and minimum demand, and generation adequacy forecasts for the Territory's regulated power systems over the 10-year outlook period from 2020-21 to 2029-30 (outlook period). It focuses on a single business-as-usual scenario, which forecasts and considers consumer demand over the outlook period against the current operating state of the power system, including committed new investments and scheduled decommissioning (discussed in detail in Appendix A Methodology and assumptions).

The outlook includes:

- annual system energy consumption and maximum and minimum demand forecasts for the three regulated power systems in the Territory
- future supply projections, including committed new projects and scheduled decommissioning of existing generators
- generation supply adequacy assessments.

The 2020 NTEOR was produced predominantly by the Australian Energy Market Operator (AEMO) on behalf and with the assistance of the Commission, in accordance with section 45 of the *Electricity Reform Act 2000*, and is restricted to the Territory's regulated power systems. Accordingly, the Commission supports the analysis, conclusions and recommendations made on its behalf by AEMO.

The main purpose of the NTEOR is to inform decisions by government, licensees, investors and electricity consumers by providing forecasts of prospective trends in system demand and supply reliability to identify challenges, gaps or opportunities.

While AEMO has sought to model risks arising from the current operating state of the regulated power systems, including the associated controls applied by Power and Water Corporation (PWC) System Control, neither AEMO nor the Commission has considered whether the current operating assumptions (detailed in Appendix A Methodology and assumptions) are appropriate in terms of risk aversion or operating cost.

AEMO has deployed a methodology similar to that used in previous years, although scrutinised updated inputs to ensure they align with recent power system outcomes and expectations. Further detail about the performance assessment can be found in Appendix C Forecasting performance.

Unlike previous years, the 2020 NTEOR does not include forecasts of consumer demand at the zone substation level or an assessment of the adequacy of the fuel supply in the Territory. The Commission decided to focus its resources on other areas of the 2020 NTEOR, noting it is not obligated to include these assessments, however may reconsider their inclusion in future outlooks.

Key findings and recommendations

The electricity industry in the Territory, like elsewhere in Australia, is continuing to experience a rapid transformation, primarily driven by large growth in asynchronous distributed solar photovoltaic (PV) systems on residential and commercial premises (distributed PV), which is displacing synchronous generation. This transformation presents both challenges and opportunities, for governments, industry, regulators and rule makers across Australia and the world, in all electricity markets and associated power systems.

In some power systems the growth of asynchronous generation has been so fast that the market and or market rules have not adapted to avoid the risks to system security and reliability from such rapid growth. For the Territory's power systems, which are small, isolated, lacking in diversity of renewable energy technologies and without appropriate supporting frameworks, the challenges and opportunities are likely greater and certainly immediate in terms of needing urgent attention to protect the long-term interests of Territory electricity consumers.

Through the Commission's assessment of a business-as-usual scenario, based on current trends the Commission has identified, and discusses in this outlook, a number of these challenges and opportunities. These include:

- Territory Generation's planned retirement of significant thermal generation capacity in the Darwin-Katherine power system
- decreasing minimum system demand to historic levels due to increasing distributed PV in the Darwin-Katherine and Alice Springs power systems
- the shortage of capacity to meet system security requirements (also referred to as essential system services) and potential subsequent reliability and security trade-offs in the Darwin-Katherine and Alice Springs power systems.

The Commission is concerned the Territory is lacking a clear framework by which these concerns can be addressed in the most efficient and timely manner. While the Commission does not seek to recommend specific solutions in all cases to mitigate emerging risks, as solutions are often varied, extensive and complex, and are not within the scope of the NTEOR, there are three key, overarching themes or 'big risks' that must be addressed urgently.

These three overarching themes or 'big risks' are discussed below and would ideally be addressed by industry through a competitive market sending the appropriate price signals to incentivise an industry response to the changing circumstances. A market approach is more likely to encourage innovation and achieve dynamic efficiency, and would avoid the risk being shouldered by taxpayers. However, partly due to the Territory's small size and partly the need to act now, the industry requires immediate, clear government direction and, in some cases, direct government action. Notwithstanding this, industry's involvement is vital to encourage innovation, achieve the changes needed at least cost and to share the risk.

The first key theme or 'big risk' is in relation to Territory's Generation's planned retirement of six large generators at the Channel Island power station and three generators at the Katherine power station¹ from 2026-27. If this generation is not replaced in time,

¹ Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like for like' replacement in the second half of 2020-21, which may change assumed retirement dates.

these retirements are forecast to lead to a serious reliability risk and an unacceptable level of outages for customers. This matter was raised in the 2018-19 NTEOR, with a recommendation that the timing to commence the process to investigate, procure, construct, commission and test a solution or solutions is now. While it is likely Territory Generation has commenced the investigation process, the Commission considers it vital to first determine what the Darwin-Katherine power system will need, in terms of both capacity and essential system services, not only in five years but over the 30 plus year life of new generators. This should be determined by government, with the Power System Controller's assistance. Leaving Territory Generation alone to do the work and propose the solution to government risks a potential suboptimal decision from a whole of system perspective that consumers and taxpayers would pay for over many decades.

Secondly, and also raised in the 2018-19 NTEOR, is the need for government to accelerate the electricity market reform program, particularly in relation to essential system services. The outlook forecasts decreased minimum system demand to levels expected to displace supply provided by large-scale synchronous generators such that system security cannot be maintained. System Control is currently managing the challenges at a significant cost to Territory Generation and ultimately Territory consumers and taxpayers. However, the government, or System Control must urgently and clearly define what services are needed to address current and future security challenges, and whether some of these services are best delivered by a government monopoly at a regulated price and or some are best delivered through a competitive process, with an appropriate market mechanism to support this. The Commission acknowledges work is being done by the Office of Sustainable Energy and the Department of Treasury and Finance in this regard, however the Commission is concerned that to date the Northern Territory Electricity Market (NTEM) Priority Reforms may not have been given enough priority by the Territory Government. The NTEM Priority Reforms need to be well supported with appropriate resources and expertise.

Thirdly, and interrelated with the two key themes above, is the forecast capacity shortfall to meet system security requirements in Darwin-Katherine and Alice Springs combined with System Control's fluid approach to managing the power system, which is arguably necessary given the current challenges but is potentially increasing the risk of a system black. Based on feedback provided by licensees, it appears capacity to meet system security requirements may be neglected during times when the supply-demand balance is tight to avoid disconnecting consumers. Assuming the form and level of system security requirements are appropriately determined and set by System Control, by not maintaining these requirements in order to avoid disconnecting some consumers, the overall power system operation may be less secure and at an increased risk of a major incident. The Commission considers this approach is not sustainable and recommends these reliability and security trade-offs be carefully managed or resolved.

In summary, the Commission acknowledges these are challenging issues and not unique to the Territory, but strongly recommends the Territory Government prioritise its electricity market reforms and accelerate work as time is running out to meet the emerging risks. Further delays will mean less time to respond. The Commission is concerned that rushed 'reactionary' decisions will come with increased risk and or cost.

Below sets out the specific outlook findings by power system.

Darwin-Katherine

- System demand decreased in 2019-20 compared with previous years due to the closure of industrial loads but is forecast to increase slowly. These forecast increases are driven by projected population growth, offset to some extent by an increasing penetration of distributed PV.
- System minimum demand is forecast to decline to below 40 megawatts (MW) by the end of the outlook period, due to increasing penetration of distributed PV. This will likely lead to system security challenges without further measures to mitigate this risk.
- A number of units at the Channel Island and Katherine power stations are scheduled to retire from 2026-27². These retirements are not offset by currently committed generation and battery investments.
- As a result, expected unserved energy (USE)³ is forecast to increase, significantly exceeding the assumed reliability standard from 2026-27. This signals the need for additional investment in new generation, storage and demand response, or deferral of scheduled generator retirements. Optimised scheduling of planned outages may help reduce USE.
- The reliability outlook has improved when compared with the previous year's outlook. This is attributable to reduced industrial demand, stronger forecast uptake of distributed PV and the newly committed battery energy storage system (BESS) in the Darwin region that should reduce forecast curtailment of renewable energy generation.
- A PWC System Control issued notification at the start of 2021 declaring an extended non-reliable operating state in the Katherine region highlighted that the reliability outlook of the region is not being explicitly assessed. To better understand future reliability levels and risks for consumers in the Katherine region, the Commission will investigate whether explicitly identifying USE in the region in future NTEORs is feasible, including consideration of the costs and benefits.
- Curtailment of large-scale solar PV⁴ is forecast to peak at 1.7% of total large-scale solar PV generation in 2028-29, with 73% and 26% of curtailment over the outlook being attributable to maintaining system security requirements and the constraint on the 132 kilovolt (kV) transmission line between Channel Island and Katherine, respectively.
- While curtailment due to the constraint on the 132 kV transmission line is forecast to be low, the constraint is forecast to increasingly curtail generation output south of Channel Island. This highlights the need for holistic consideration of new investments in generation, transmission and or storage to effectively mitigate forecast risks.
- Renewable energy generation as a percentage of underlying consumption (total consumption at consumers' power points) increased from 5% in 2018-19 to 6% in 2019-20. Based on existing installation rates of distributed PV and committed large-scale solar PV projects only, renewable energy generation is forecast to increase over time to meet 23% of underlying consumption by 2029-30.

2 Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like for like' replacement in the second half of 2020-21, which may change assumed retirement dates.

3 USE is energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply) as a result of insufficient levels of generation capacity, demand response or network capability, to meet demand. 'Expected' refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

4 Curtailment in the 2020 NTEOR only considers the assumed security requirements listed in Appendix A Methodology and assumptions.

Alice Springs

- System demand is expected to increase in 2021-22 when a new load is connected to the network and then forecast to be flat over the remaining outlook period.
- The assumed connection of the Joint Defence Facility Pine Gap (JDFPG) to the Alice Springs power system in 2021-22 is a positive for the system in terms of minimum system demand, by delaying immediate challenges to later in the outlook period. However, any delay to this connection may see immediate challenges associated with managing low levels of minimum system demand in the power system continue or intensify over the coming years.
- Following the assumed retirement of the Ron Goodin power station in July 2022⁵, expected USE is forecast to increase but does not exceed the Commission's adopted reliability standard.
- The ability to meet system security requirements is forecast to substantially decrease following the assumed retirement of the Ron Goodin power station, highlighting emerging security and operability risks, and greater renewable energy curtailment.
- The reliability outlook has improved when compared with the previous year's outlook. This is attributable to lower forecasts of demand and less coincident planned outages. This highlights the importance of ongoing coordination in the planning of outages.
- Curtailment of large-scale solar PV is driven primarily by assumed spinning reserve requirements. Curtailment is forecast to continue increasing each year of the outlook due to the forecast growth in distributed PV installations. As the only large-scale solar PV generator in the Alice Springs power system, curtailment in the system refers exclusively to the Uterne solar power station, which is forecast to start at 3.3% of total output in 2020-21 and increase to 4.1% in 2029-30.
- Renewable energy generation as a percentage of underlying consumption (total consumption at consumers' power points) increased from 8% in 2018-19 to 10% in 2019-20. Based on existing installation rates of distributed PV, noting there are no committed large-scale solar PV projects, renewable energy generation is forecast to increase over time to meet 14% of underlying consumption by 2029-30.

Tennant Creek

- System demand is forecast to increase in the short term, driven by a new mine development, but then to decline following projected population decreases.
- There is substantial surplus generation capacity over the entire outlook period, resulting in no material levels of forecast USE or challenges meeting security requirements.
- Renewable energy generation as a percentage of underlying consumption (total consumption at consumers' power points) marginally increased from 2018-19 to 2019-20 and remains at 2%. Based on existing installation rates of distributed PV, noting there are no committed large-scale solar PV projects, renewable energy generation is forecast to increase over time, but will remain at 2% of underlying consumption by 2029-30.

⁵ The retirement date was assumed by AEMO to be July 2022, as Territory Generation did not provide a date. July 2022 is one year later than was assumed in previous outlooks.

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1 | Darwin-Katherine

This chapter focuses on the demand and supply outlook for the Darwin-Katherine power system over the 10-year outlook period from 2020-21 to 2029-30 and considers:

- annual and average consumption, maximum and minimum system demand, and system and underlying daily load profile
- unserved energy outcomes, reserve capacity, impact of system security requirements, renewable energy curtailment and system minimum implications.

The outlook assumes continuation of expected growth in electricity consumption, maximum system demand, uptake of distributed residential and commercial solar PV, and includes existing and currently committed new large-scale solar PV capacity.

Demand history and forecasts

Key outcomes

- Annual system consumption in 2019-20 was 4.3% lower than in 2018-19, primarily due to the shutdown or disconnection from the network of large loads, and increased uptake of distributed PV.
- Annual system consumption in 2020-21 is forecast to remain reasonably constant, with a 0.1% drop compared with 2019-20. Consumption is then forecast to slightly increase over the outlook period, in line with population projections, but offset by increasing distributed PV.
- Maximum system demand in 2019-20 occurred in the wet season at 272 MW, which was 14 MW lower than the previous year due to multiple large loads shutting down or disconnecting from the network. Given no further forecast shutdowns or disconnections from the network of large loads is assumed, maximum system demand is forecast to grow at around 0.9% per annum over the outlook period.
- The timing of maximum system demand is forecast to shift, as is already occurring, from mid to later in the afternoon or early evening due to increases in installed distributed PV capacity.
- In 2019-20, minimum system demand occurred during the middle of the day in the shoulder season for the first time, having previously occurred in the early morning in the dry season. While the observation is likely an anomaly, the forecast minimum system demand from season year (year ending 31 August) 2020-21 occurs in the middle of the day in the dry season, driven by increasing levels of distributed PV.
- Minimum system demand was 67.7 MW in 2019-20, significantly lower than the 93.37 MW minimum in 2018-19, and is forecast to decrease below 40 MW by the end of the outlook period.

Annual and average consumption

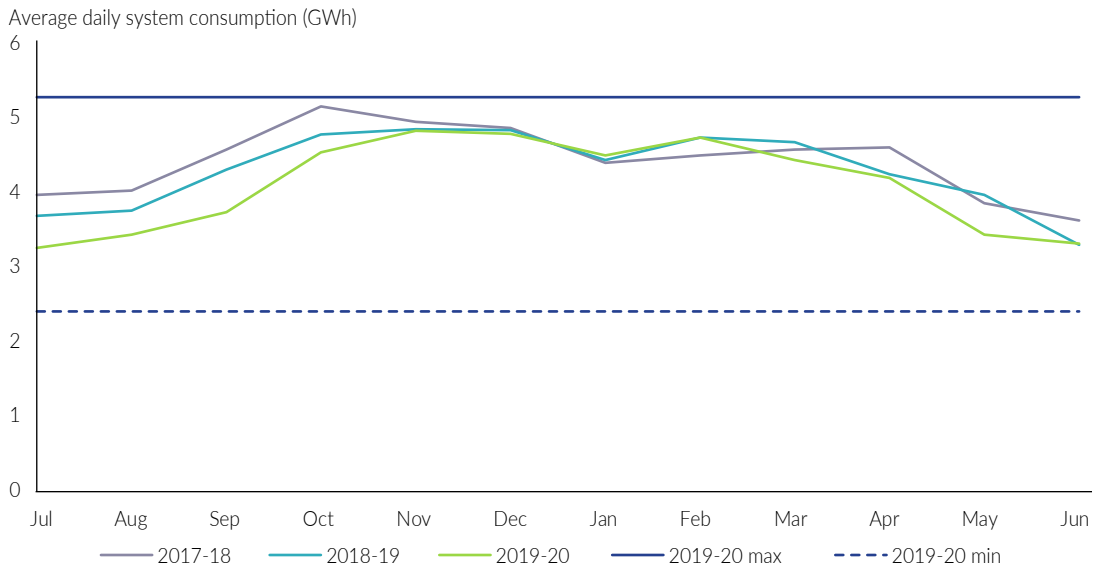
Levels in 2019-20

In 2019-20, the total annual system consumption in the Darwin-Katherine power system was 1,505 gigawatt hours (GWh). This was 4.3% lower compared with 2018-19. This reduction was in part caused by the continued growth in distributed PV-installed capacity, which increased from 59.4 MW to 77.9 MW over the 2019-20 financial year. The closure of Cosmo mine late in the 2019-20 financial year also contributed to the reduction in system consumption.

Figure 1 shows average daily system consumption by month over the past three financial years in the Darwin-Katherine power system. Average daily system consumption in 2019-20 was 4.1 GWh, and maximum and minimum daily consumption were 5.3 GWh and 2.4 GWh, respectively.

The month-to-month variability of system consumption in the Darwin-Katherine power system indicates that seasonal variability exists between the wet and dry seasons. As additional distributed PV is installed over time, these seasonal differences may become more pronounced, with less system consumption during the dry season.

Figure 1: Average daily system consumption for Darwin-Katherine by month, 2017-18 to 2019-20



Forecasts

Figure 2 shows historical and forecast annual system consumption in the Darwin-Katherine power system from 2015-16 to 2029-30. The recent historic trend in annual system consumption is in decline. This trend has been driven by increases in distributed PV and the closure or disconnection from the network of several industrial sites, including a temporary load associated with the construction of INPEX infrastructure (whereby load drastically reduced from 2017-18), Union Reef (that shutdown in early 2018-19), and Cosmo mine (shut down in late 2019-20). The shutdown of Cosmo mine late in 2019-20 contributed to the forecast initially being below recent levels.

Figure 2 also shows annual system consumption is forecast to slightly increase over the outlook period, noting however that no further large shutdowns are considered in the forecast. Prior to 2024-25, increases in system consumption are due to projected population growth (see Table 2 in Appendix A Methodology and assumptions for details on population growth) but are offset by forecast growth in distributed PV. From 2024-25 onwards, a modest increase in forecast annual system consumption is driven by a higher population growth rate and assumed saturation of distributed PV.

Figure 2: Historical and forecast annual system consumption for Darwin-Katherine, 2015-16 to 2029-30

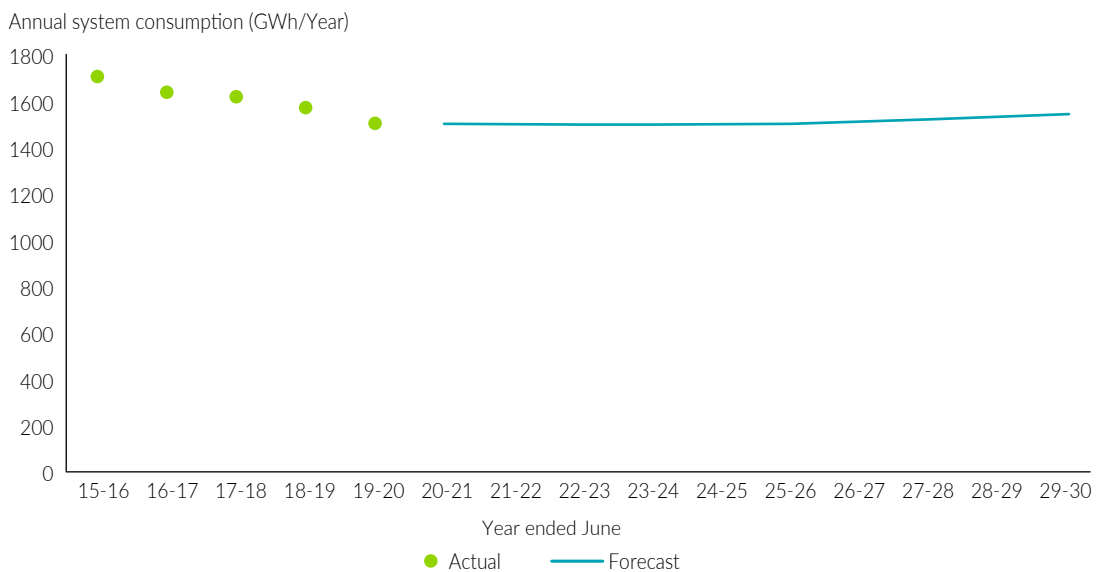
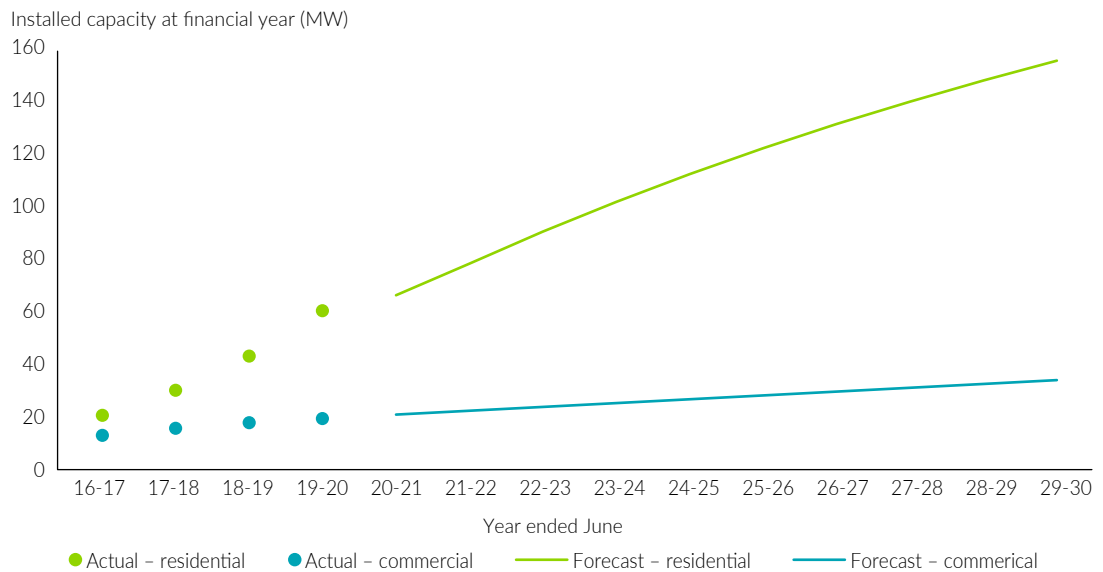


Figure 3 shows the historical and forecast distributed PV-installed capacity for Darwin-Katherine from 2016-17 to 2029-30.

Figure 3: Historical and forecast distributed PV-installed capacity for Darwin-Katherine, 2016-17 to 2029-30



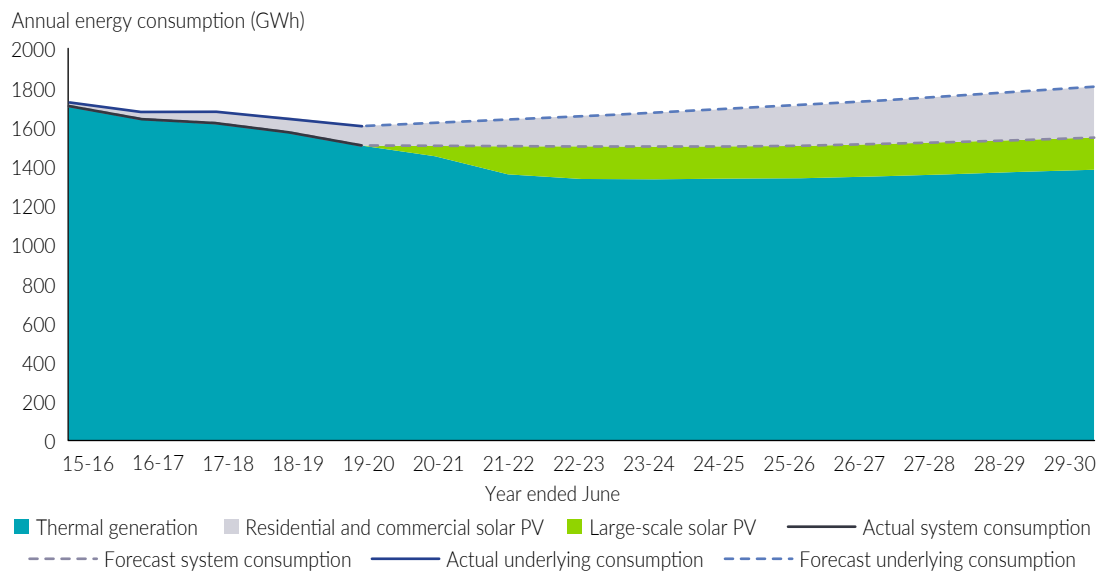
The smaller increase in installed distributed PV capacity from the 2019-20 actual to the first forecast year in 2020-21, compared with increases in previous historical years, is attributed to the winding back of the Northern Territory Home Renovation Grant and the decrease in the solar feed-in tariff. From 2021-22, the forecast returns to the trend of previous years and then begins to taper off due to saturation in installed capacity in the long term.

Darwin-Katherine commercial distributed PV forecasts are increasing at a rate resembling recent years. Despite the drop in recent distributed PV installation rates, the forecasts are higher compared with last year, reflecting a trend seen in distributed PV forecasts in other parts of Australia. As of June 2020, actual residential and commercial distributed PV capacity totalled 59 MW and 19 MW, respectively. By 2029-30, residential and commercial distributed PV capacity is forecast to increase to 152 MW and 33 MW, respectively.

Figure 4 shows how historical and forecast annual system consumption was and is forecast to be met by different generation categories in the Darwin-Katherine power system from 2015-16 to 2029-30. This assessment includes only existing and committed generators and may be impacted by further new generator commitments. By 2029-30, the combined generation from residential, commercial, and large-scale solar PV is forecast to meet about 23% of underlying consumption.

Figure 4 does not show the large-scale solar PV that is forecast to be curtailed due to periods where supply exceeds demand. This curtailed energy would need to be stored – using technology such as batteries – for later use, or demand shifted (demand management) in order to displace further dispatchable thermal generation, to achieve a higher percentage of renewable energy consumption. Renewable energy curtailment is discussed later in this chapter.

Figure 4: Historical and forecast annual consumption met by generation types, for Darwin-Katherine, 2015-16 to 2029-30



Maximum demand

Figure 5 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different probability of exceedance (POE) levels in the Darwin-Katherine power system from 2015-16 to 2029-30.

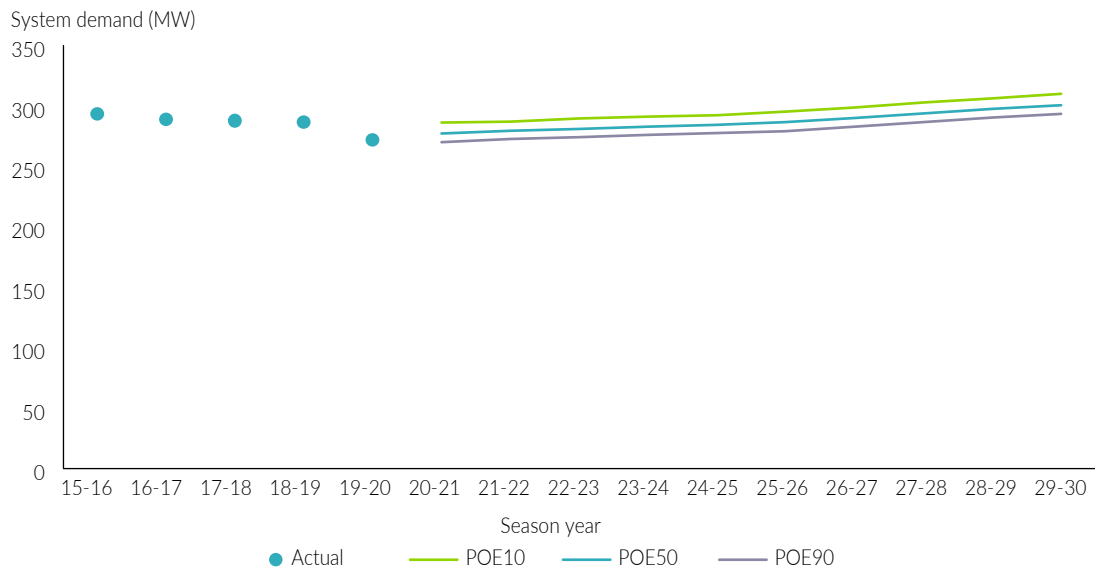
Maximum system demand has historically occurred in the wet season in the mid-afternoon, driven by loads associated with cooling. The time of maximum system demand is trending later in the day due to increasing penetration of distributed PV in the region, with the 2019-20 maximum system demand occurring at 18:30.

Maximum system demand is forecast to grow over the outlook period with a POE50⁶ compound annual growth rate of 0.9% per annum. Population growth is forecast to drive annual maximum system demand higher, although this trend is tempered by the forecast increases of distributed PV-installed capacity, which will also further push the forecast time of maximum system demand later in the day. Once this has been pushed beyond sunset, there is expected to be no further impact of distributed PV on maximum system demand. The wet season maximum system demand is forecast to occur between 18:00 and 19:00 over the outlook period.

The recent shutdown of Cosmo mine that reduced maximum system demand in 2019-20 has been captured in the forecasts.

⁶ In a POE50 forecast the maximum/minimum value is expected to be exceeded, on average, one year in two.

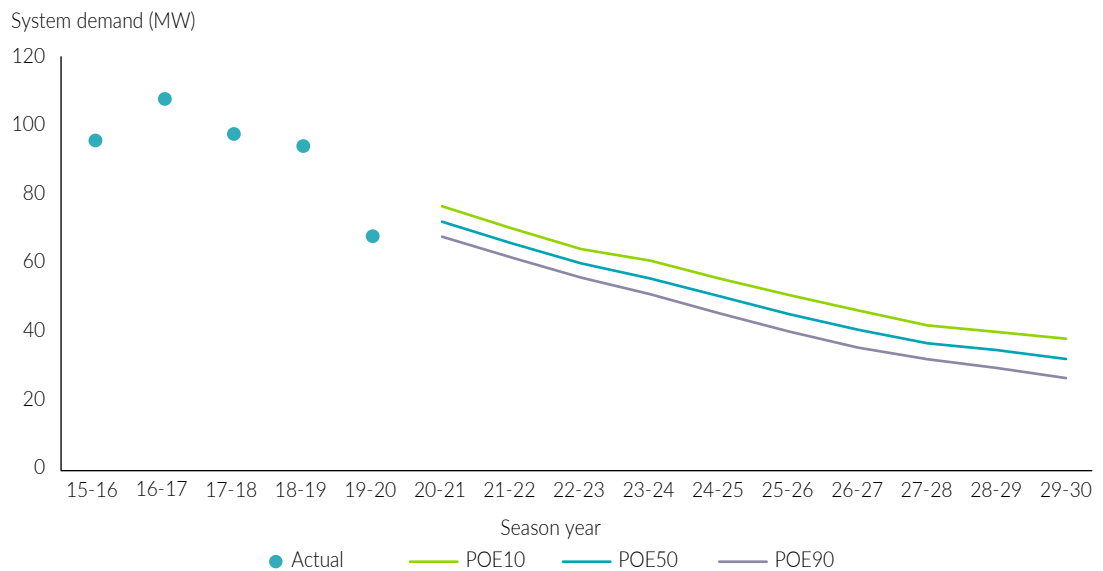
Figure 5: Historical and forecast maximum system demand for Darwin-Katherine, season years (year ending 31 August) 2015-16 to 2029-30



Minimum demand

Figure 6 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Darwin-Katherine power system from 2015-16 to 2029-30.

Figure 6: Historical and forecast minimum system demand for Darwin-Katherine, season years (year ending 31 August) 2015-16 to 2029-30



Minimum system demand has historically occurred early morning in the dry season, however, in 2019-20, a midday minimum occurred during the shoulder season. This midday minimum system demand of 67.7 MW is unusually low. While not associated with a power system event or fault, the observed minimum is out of character with typical demand profiles. The next lowest minimum (84.9 MW), which occurred in the early morning in the dry season, better matches the historical trend.

Minimum system demand is forecast to continually decrease over the outlook period, due to increasing installation of distributed PV, with the POE50 minimum system demand forecast to decrease at a rate of 8.7% per annum. The minimum system demand forecasts show a shift in time of day to late morning during the dry season from as early as 2020-21, driven by increasing levels of installed distributed PV.

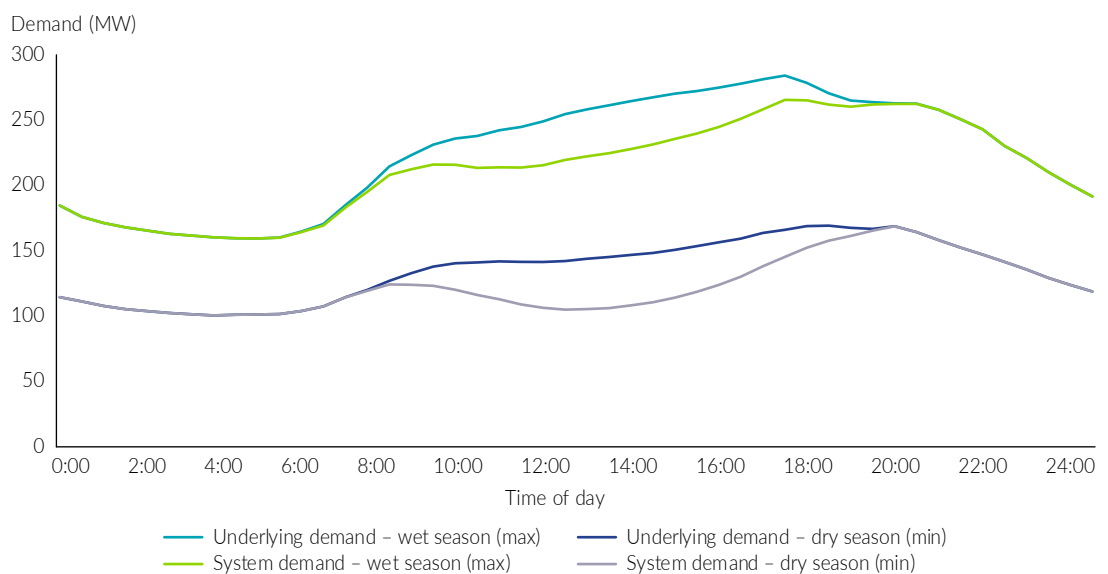
AEMO notes there remains a possibility of outcomes that are considered as outliers and below the POE90⁷ minimum demand forecast, as seen in Darwin-Katherine in 2019-20.

System and underlying daily load profile

Figure 7 shows typical daily load profiles, including underlying and system demand, under maximum and minimum demand conditions in the Darwin-Katherine power system for 2019-20. System demand is consumer demand from the system (that is, demand met by large-scale network connected generators), whereas underlying demand is total energy demand at consumers' power points (that is, met by large-scale network connected generators and distributed by PV). The maximum demand profile represents the average of the 10 uppermost demand values in the wet season, whereas the minimum demand profile represents the average of the 10 lowermost demand values in the dry season.

The light blue and green lines represent the wet season maximum underlying and system demand, respectively. The dark blue and purple lines represent the dry season minimum underlying and system demand, respectively. As expected, distributed PV generation during the day has lowered maximum system demand in the wet season. While distributed PV has lowered the daytime minimum system demand in the dry season, the minimum system demand still occurred overnight. The impact from distributed PV during the day is similar for both seasons although it is slightly greater for the dry season. For the most part, the 10 uppermost demand days in the wet season are clear sky days, which maximise the impact from distributed PV.

Figure 7: Daily load profiles for Darwin-Katherine, wet and dry seasons, 2019-20



7 In a POE90 forecast the minimum demand value is expected to be exceeded, on average, nine years in 10.

Supply adequacy outlook

Key outcomes

- Expected USE in the Darwin-Katherine power system is forecast to remain below the Commission's adopted reliability standard of 0.002% of forecast annual underlying energy consumption from 2020-21 to 2026-27.
- Large amounts of USE are forecast from 2027-28, mainly due to significant retirements of thermal generation expected after December 2026. This indicates that additional generation, deferred generator retirements, demand response and or storage will be required to offset the impact of these retirements to maintain the current level of reliability.
- System security requirements are also forecast to be regularly breached after the retirements and in years with simultaneous planned outages of the large thermal generating units.
- Large-scale solar PV curtailment is forecast to steadily increase in the first years of the outlook period, initially as a result of increased distributed PV generation and in the latter years due to the retirement of units with high inertial response (resulting in large-scale solar PV being curtailed in order to manage system security and transmission constraint requirements).

Unserviced energy outcomes

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). An assessment of USE, or generation adequacy assessment, is used by the electricity supply industry and Commission to determine whether available generation capacity, including an allocation for potential outages, is sufficient to meet consumer demand (reliability). This is determined by comparing the level of forecast USE with the Commission's reliability target of 0.002% (adopted in the absence of a formal Territory target).

The generation adequacy assessment, and following assessments in this section, include the assumed new entrants listed in Table 1.

Table 1: Darwin-Katherine power station new entrants

	Main fuel type	Estimated summer capacity (MW)	Assumed commissioning date
Hudson Creek	Gas	14.4 (it is expected that no more than five of the six 2.4 MW generators will operate at any one time)	1 September 2021 ¹
Batchelor 2 Solar Farm	Solar	10.0	1 September 2021 ¹
Eni Australia Limited Batchelor Solar	Solar	10.0	30 September 2021
Eni Australia Limited Manton Solar	Solar	10.0	30 November 2021
Eni Australia Limited Katherine Solar	Solar	25.0	28 February 2021
Territory Generation Darwin BESS ²	–	35.0 (assumed to meet all security requirements currently provided by a Frame 6 machine ³)	1 September 2022 (assumed)
RAAF Darwin ⁴	Solar	3.2	1 April 2022 (assumed)
Robertson Barracks ⁴	Solar	10.0	1 April 2022 (assumed)

1 Assumed based on information provided by licensees, supplemented by the licence transfer application. See <https://utilicom.nt.gov.au/publications/licence-applications/licence-transfer-application-trutininor-nt-pty-ltd> and <https://utilicom.nt.gov.au/publications/licence-applications/licence-transfer-application-batchelor-solar-farm-pty-ltd>.

2 The BESS is expected to impact security requirements, and therefore impact supply availability indirectly, rather than directly through energy provision.

3 Channel Island units 1, 2, 4, and 5 are referred as Frame 6.

4 These two units were considered 'behind the meter' in last year's NTEOR and were not modelled as individual units.

Expected USE in the Darwin-Katherine power system is forecast to be relatively low and stable in the initial years of the outlook except for the first year, 2020-21. In 2020-21, large USE is forecast due to long periods with concurrent known planned outages of two generating units at the Channel Island power station, however Territory Generation has advised that strategies have and will be deployed to mitigate these risks. The forecast level of expected USE increases substantially in the latter years of the outlook period after the retirement of a number of generating units at the Channel Island and Katherine power stations⁸ (see Appendix A Methodology and assumptions Table 4). Detailed USE forecasts are shown in Appendix B Supply details.

Figure 8 shows the year-by-year results. The last three years of the outlook have been shown separately on a new axis due to the magnitude of the forecast USE. USE is forecast to exceed 0.9% of annual underlying energy consumption in the final year of the outlook. This indicates that additional generation, demand response and/or storage solutions will be required to offset the impact of generation retirements to maintain the current level of reliability.

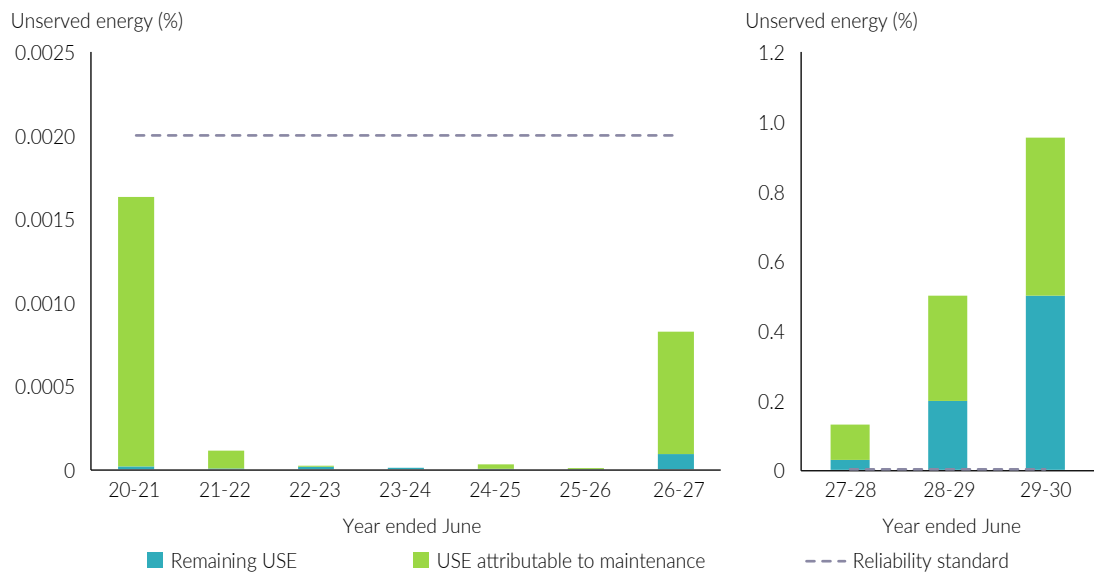
With the exception of 2020-21, the USE forecast in this outlook in the Darwin-Katherine power system is lower than was forecast in the 2018-19 NTEOR. This is mostly due to the

⁸ Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like for like' replacement in the second half of 2020-21, which may change assumed retirement dates.

lower forecasts of system consumption and maximum demand, a new battery commitment in the Darwin region and changed outage assumptions.

Figure 8 also shows the amount of USE caused by planned outages for maintenance, shown by the green columns. The level is significant in 2020-21 and demonstrates a lower USE result is possible if the scheduling of known planned outages is optimised to avoid times when the supply-demand balance is forecast to be tight. There is a period in October 2020 when more than 90 MW of generation capacity was forecast to be concurrently scheduled to undergo maintenance. Given the magnitude of the risk in October 2020 and the remainder of 2020-21, Territory Generation has advised that strategies (not included in this modelling) have and will be deployed to mitigate these risks.

Figure 8: Forecast reliability, Darwin-Katherine, 2020-21 to 2029-30

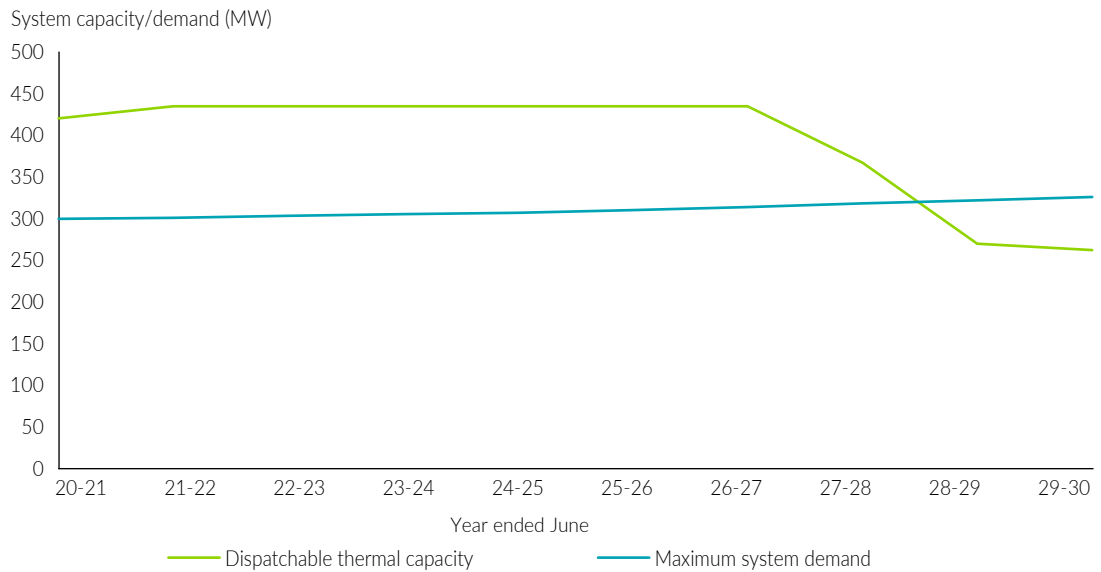


Reserve capacity

The main cause for the forecast increase in expected USE in the Darwin-Katherine power system towards the end of the outlook period is the significant lack of capacity after the planned retirement of units at the Channel Island and Katherine power stations⁹ from 2026-27. Figure 9 shows the reduction in dispatchable thermal capacity against the wet season maximum system demand forecast. This figure does not account for the contribution from non-thermal sources, such as the large-scale solar PV power stations discussed in Appendix A Methodology and assumptions.

⁹ Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like for like' replacement in the second half of 2020-21, which may change assumed retirement dates.

Figure 9: Forecast wet season dispatchable thermal capacity and maximum system demand (POE10¹⁰), Darwin-Katherine, 2020-21 to 2029-30



Impact of system security requirements

AEMO modelled three system security requirements in the Darwin-Katherine power system: regulating reserve, spinning reserve and an inertia requirement (see Appendix A Methodology and assumptions for more information about the different requirements).

A power system should be managed to maintain reliability (that is, there is enough supply from the system to meet consumer demand) and system security (that is, minimising the risk of a major system event such as a system wide blackout). However, based on feedback provided by licensees, in practice capacity to meet system security requirements may be neglected during times when the supply-demand balance is tight to avoid disconnecting consumers. Accordingly, the forecasts of expected USE in Figure 8 assume numerous breaches of the system security requirements, whereas if all system security requirements were required to be maintained, forecast expected USE would have been much higher.

Providing the form and level of the system security requirements are appropriately determined and set by PWC System Control, AEMO notes that in not maintaining the system security requirements in order to avoid USE to some consumers, the overall power system operation may be less secure and at an increased risk of a major event, including a system black. These reliability and security trade-offs need to be carefully managed.

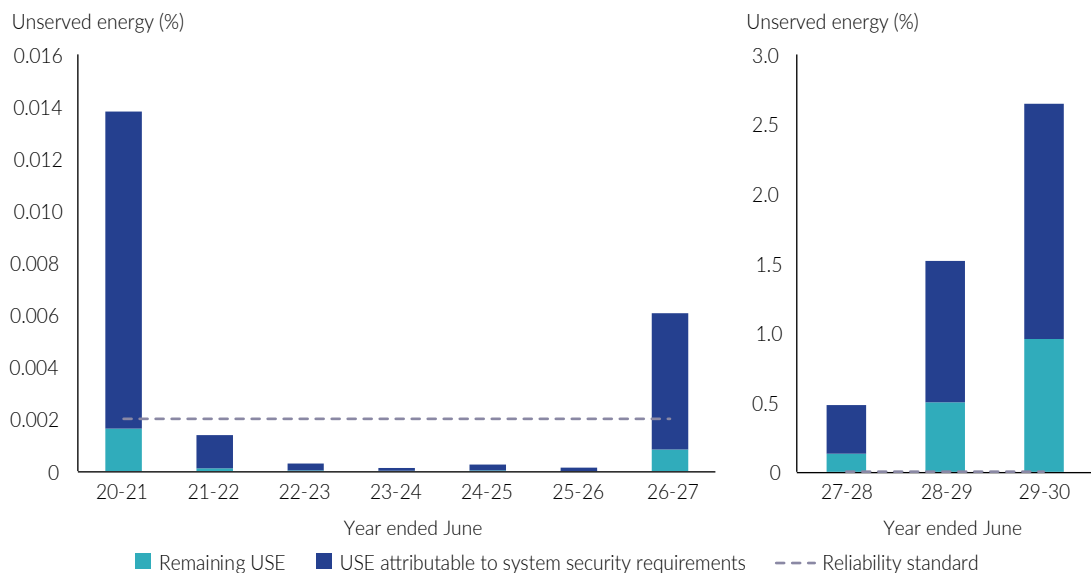
To highlight the impact of maintaining system security requirements, AEMO forecast the expected USE again, this time assuming the system security requirements must be maintained at all times.

Figure 10 shows forecast USE under scenarios where system security requirements are not maintained to meet demand (light blue columns) and when system security requirements are maintained to meet demand (light and dark blue columns combined). The 'USE attributable to system security requirements' in the figure demonstrates the impact of retaining capacity to meet system security requirements rather than consumer demand. While expected USE in 2029-30 is about 0.9% of annual underlying energy consumption when system security requirements are not maintained, it rises to over 2.5% of annual underlying energy consumption if system security requirements are maintained.

¹⁰ In a POE10 forecast the maximum demand value is expected to be exceeded, on average, one year in 10.

Figure 10 highlights that capacity for the provision of system security requirements is scarcer in 2020-21 and 2026-27. This is due to several concurrent known planned outages of generation units that provide regulating and spinning reserve. In the final years of the outlook period, the scarcity of capacity for the provision of system security requirements is due to the retirement of thermal generating units at the Channel Island and Katherine power stations¹¹.

Figure 10: Forecast effect of strict upkeep of system security requirements in USE (%), Darwin-Katherine, 2020-21 to 2029-30



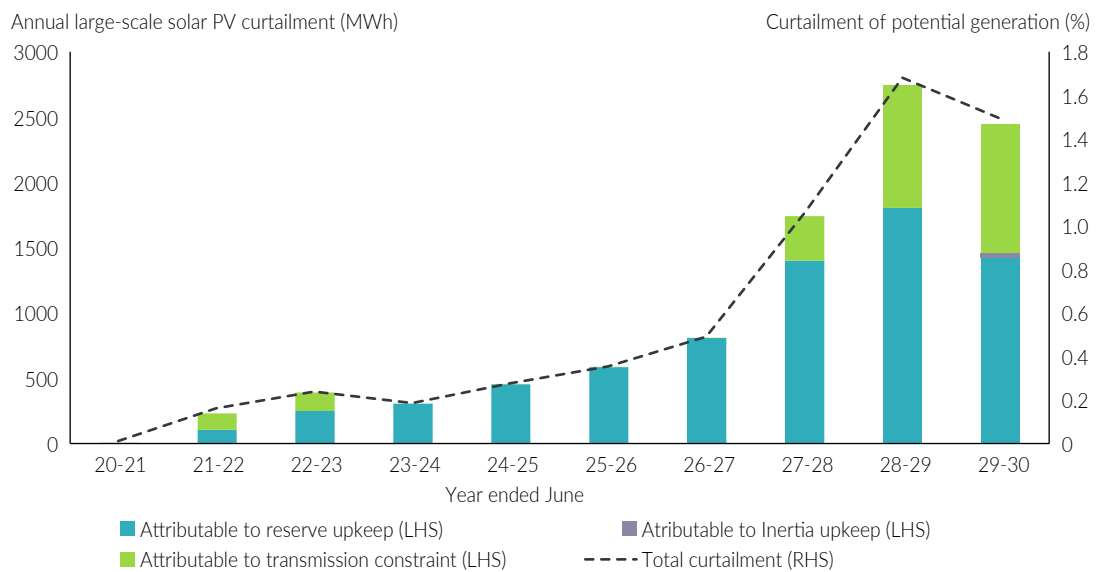
Renewable energy curtailment

Renewable energy curtailment in the Territory refers exclusively to solar PV, and specifically large-scale solar PV given the current lack of ability to curtail distributed PV. Renewable energy curtailment occurs when peak solar production coincides with periods of relatively low demand or solar energy production needs to be curtailed to preference thermal generation (to meet the power system’s reserve and inertia requirements).

Once the large-scale solar PV generators (as discussed in Appendix A Methodology and assumptions) are operational, renewable energy curtailment in the Darwin-Katherine power system is forecast to be mostly driven by additional spinning reserve operational requirements (see Table 12 in Appendix A Methodology and assumptions for more details), as shown in Figure 11, and by the restriction of flow in the 132 kV transmission line between Channel Island and Katherine due to low inertia levels in the Darwin node.

¹¹ Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for ‘like for like’ replacement in the second half of 2020-21, which may change assumed retirement dates.

Figure 11: Forecast large-scale solar PV energy curtailment, Darwin-Katherine, 2020-21 to 2029-30



The addition of Territory Generation’s BESS in the Darwin region of the Darwin-Katherine power system is assumed to reduce the amount of curtailment attributable to the transmission line flow constraint once the BESS becomes commercially operational. However, when the inertia-providing units at the Channel Island power station start to retire in 2027-28, the 132 kV transmission line is forecast to become more constrained with some renewable energy generated south of Manton not able to flow into the Darwin region as had previously been forecast.

Renewable energy curtailment is forecast to start at 0.16% of total large-scale solar PV generation in 2021-22 and peak at 1.7% in 2028-29. It should be emphasised that these values only consider the assumed security requirements listed in Appendix A Methodology and assumptions, and do not take into consideration potential curtailment due to other requirements, such as capacity forecast errors associated with the Network Technical Code standards, or any other PWC System Control issued risk notification requirements. Further, as previously noted, any future ability of the Power System Controller to curtail distributed PV has not been assumed over the outlook period.

System minimum implications

Minimum system demand is forecast to decline rapidly in the Darwin-Katherine power system, following the increasing penetration of distributed PV. By the end of the outlook, system minimums are forecast to be less than 40 MW, which will likely have system security implications without further measures including load shifting capability and or emergency controls.

Similar trends are evident in the National Electricity Market (NEM), where declining minimum demand raises challenges with managing voltage, system strength and inertia, and is creating near-term operational and planning challenges for sustaining a reliable and secure power system. AEMO is working with NEM stakeholders to implement new capabilities that will assist in mitigating these risks, including:

- effective market and regulatory arrangements that incentivise more demand during the middle of the day

- innovative solutions that could include providers/aggregators of distributed energy resources offering services such as increased solar PV system controllability, load flexibility, storage and load shifting
- ensuring all new distributed PV installations have suitable disturbance ride-through capabilities and emergency solar PV system shedding capabilities to be enabled under rare circumstances as a last resort to maintain system security.

For more information on risks at time of minimum system demand in the NEM, which is equally relevant to the Territory, and mitigation strategies, see AEMO's 2020 NEM Electricity Statement of Opportunities (ESOO)¹² and 2020 System Strength and Inertia Report¹³.

¹² See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf.

¹³ See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-System-Strength-and-Inertia-Report

2 | Alice Springs

This chapter focuses on the demand and supply outlook for the Alice Springs power system over the 10-year outlook period from 2020-21 to 2029-30 and considers:

- annual and average consumption, maximum and minimum system demand, and system and underlying daily load profile
- unserved energy outcomes, reserve capacity, impact of system security requirements and renewable energy curtailment.

The outlook assumes continuation of expected growth in electricity consumption, maximum system demand, uptake of distributed residential and commercial solar PV, and includes existing and currently committed new large-scale solar PV capacity, noting none have been assumed.

Demand history and forecast

Key outcomes

- Annual system consumption in 2019-20 was 4.7% lower than in 2018-19 and the lowest recorded consumption in the past five years.
- Annual system consumption is initially forecast to remain flat into 2020-21 before the JDFPG connects to the power system in 2021-22. This connection contributes to the annual system consumption forecast increasing 17.3% in a single year. Annual system consumption is then expected to remain flat at this increased level for the remainder of the outlook period.
- Maximum system demand in recent years has been about 52 MW, however is forecast to increase sharply from summer 2020-21 to summer 2021-22 due to the JDFPG connecting to the network. Maximum system demand then resumes a moderate rate of growth of 0.3% per annum, as population growth impacts are subdued by increased distributed PV-installed capacity.
- The timing of maximum system demand is typically early to mid-afternoon during the summer. As distributed PV-installed capacity is forecast to increase, the timing of summer maximum system demand is forecast to occur later in the afternoon and into early evening by 2030.
- Since 2016, minimum system demand has been observed in the middle of the day during the shoulder season, driven by distributed PV. Forecast increases in distributed PV-installed capacity will continue to push midday minimum system demand lower with a mixture of shoulder and winter minimum system demands expected.
- Minimum system demand is forecast to increase in 2021-22 by 4.2 MW, due in part to the JDFPG, with the minimum forecast to be higher than in 2019-20. Following the connection of the JDFPG, a rapid rate of reduction in minimum system demand is forecast due to continued uptake of distributed PV, with minimum system demand expected to fall below values observed in 2019-20 by early 2024-25, falling below 7.5 MW by 2029-30.

Annual and average consumption

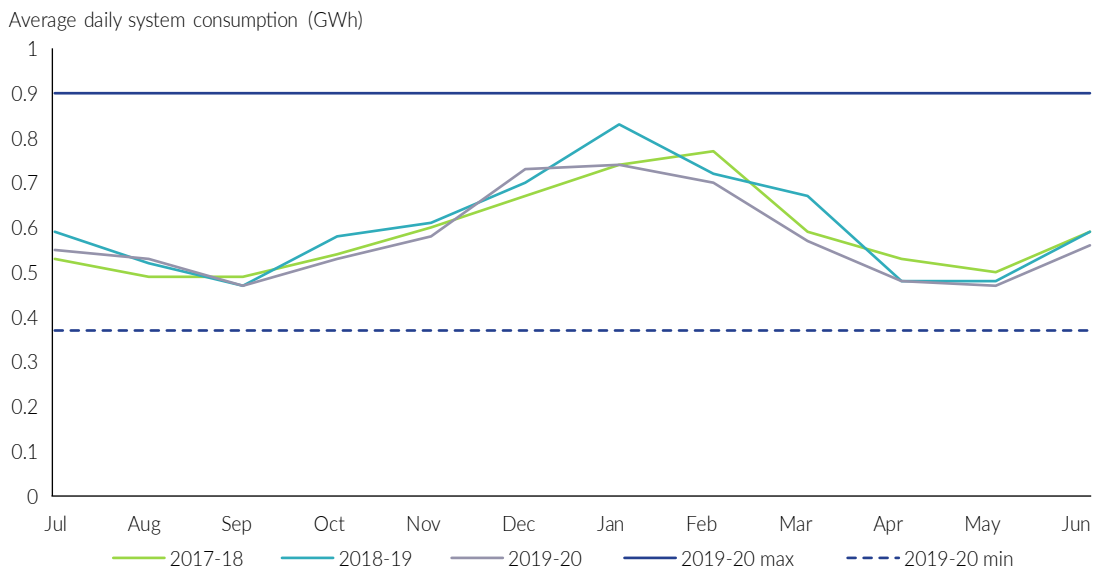
Levels in 2019-20

In 2019-20, the total annual system consumption in the Alice Springs power system was 210 GWh. This was 4.7% lower than system consumption in 2018-19.

Figure 12 shows average daily system consumption by month over the past three financial years. Average daily system consumption in 2019-20 was 0.58 GWh, and the daily maximum and daily minimum system consumption was 0.90 GWh and 0.37 GWh, respectively.

The month-to-month variability in system consumption indicates that Alice Springs has relatively strong seasonable variability.

Figure 12: Daily average system consumption for Alice Springs by month, 2017-18 to 2019-20



Forecast

Figure 13 shows historical and forecast annual system consumption in the Alice Springs power system from 2015-16 to 2029-30. Annual system consumption is forecast to remain relatively constant into 2020-21 before rising in 2021-22, largely due to the connection of the JDFPG. From 2021-22 to the end of the outlook period, annual system consumption is forecast to remain flat, as population growth is offset by increases in distributed PV.

Figure 13: Historical and forecast annual system consumption for Alice Springs, 2015-16 to 2029-30

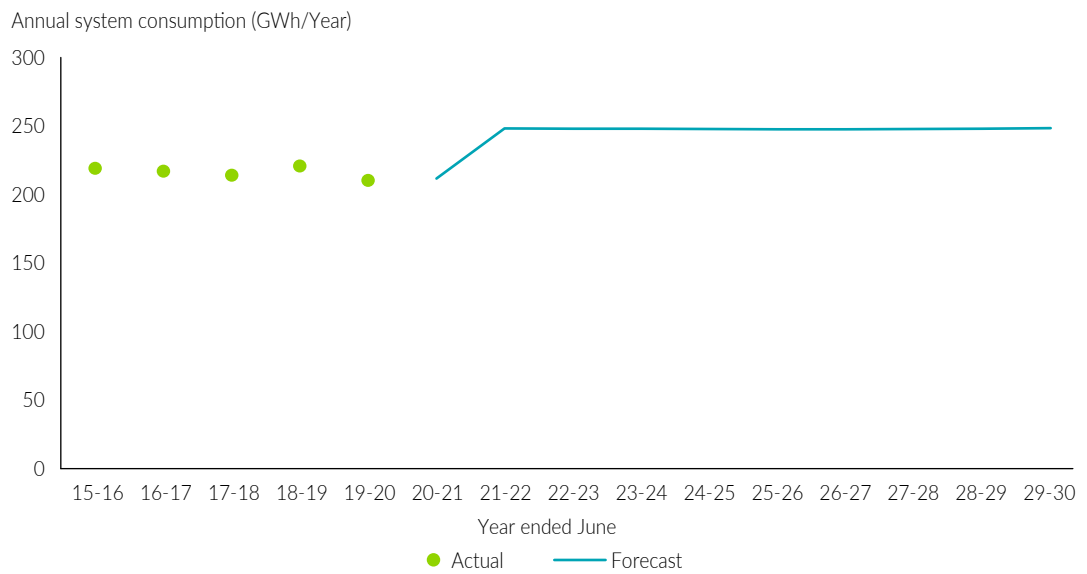
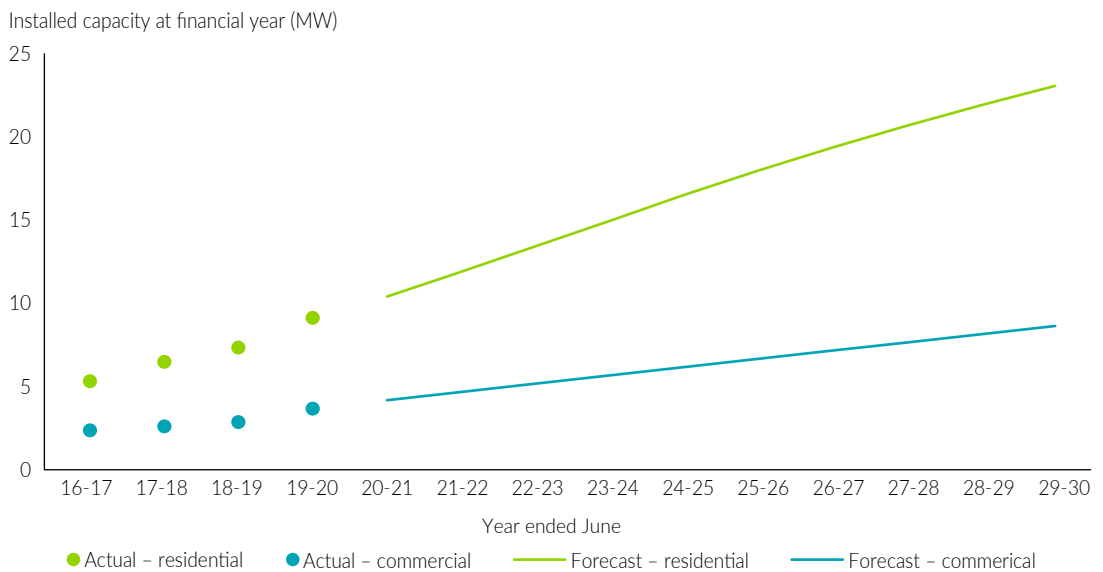


Figure 14 shows the historical and forecast distributed PV-installed capacity for Alice Springs from 2016-17 to 2029-30.

Figure 14: Historical and forecast distributed PV-installed capacity, Alice Springs, 2016-17 to 2029-30



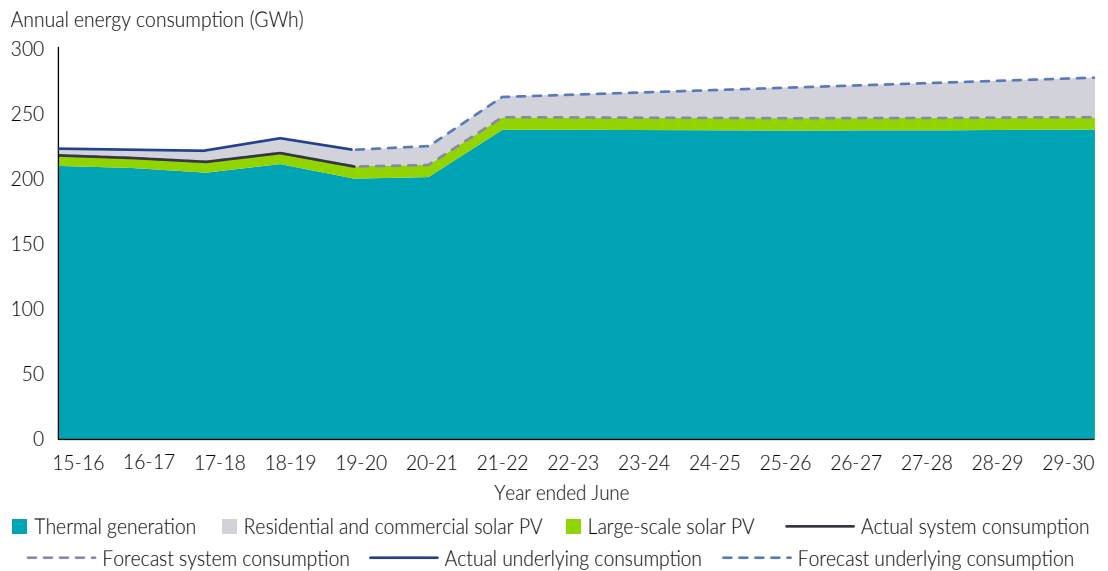
The forecast of distributed PV reflects the assumption, based on analysis of other jurisdictions, that there will be little impact on residential and commercial installations of solar PV from the reduction in incentives. The residential distributed PV forecasts begin to flatten out due to saturation of installed capacity in the long term. The forecasts are higher compared with last year, reflecting a trend seen in distributed PV forecasts in other parts of Australia.

As of June 2020, actual residential and commercial distributed PV capacity in Alice Springs totalled 9 MW and 4 MW, respectively. By 2029-30, residential and commercial distributed PV capacity is forecast to increase to 23 MW and 9 MW, respectively.

Figure 15 shows how historical and forecast annual system consumption was and will be met by different generation categories in the Alice Springs power system from 2015-16 to 2029-30. This assessment includes only existing generators and may be impacted by new generator commitments, noting none have been assumed in the outlook. The proportion of annual system consumption met by large-scale solar PV generation is forecast to be lower than that met by distributed PV generation. By 2029-30, the combined generation from residential, commercial and large-scale solar PV is forecast to meet about 14% of underlying consumption.

Figure 15 does not show the large-scale solar PV that is forecast to be curtailed due to periods where supply exceeds demand. This curtailed energy would need to be stored – using technology such as batteries – for later use or demand shifted (demand management) in order to further displace dispatchable thermal generation, to achieve a higher percentage of renewable energy consumption. Renewable energy curtailment is discussed later in this chapter.

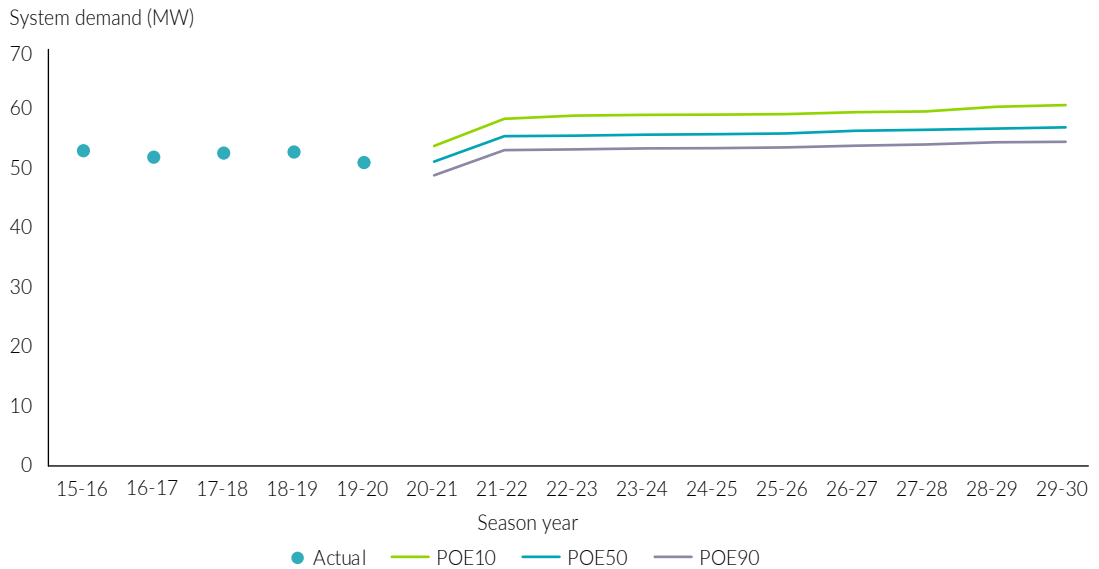
Figure 15: Historical and forecast annual consumption met by generation types, for Alice Springs, 2015-16 to 2029-30



Maximum demand

Figure 16 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2015-16 to 2029-30. Maximum system demand in Alice Springs has historically occurred in summer in the early to mid-afternoon, between 13:30 and 16:00. The time of maximum system demand is trending later in the day due to increasing penetration of distributed PV in the region.

Figure 16: Historical and forecast maximum system demand for Alice Springs, season years (year ending 31 August) 2015-16 to 2029-30



With the JDFPG connecting to the network, maximum system demand is expected to increase from July 2021. Beyond this, minor population-driven demand growth is forecast from 2021-22 onwards, with the POE50 forecast growing at a rate of 0.34% per annum.

This subdued rate of increase in maximum system demand is related to distributed PV-installed capacity, which is forecast to continue to increase over the outlook period. The increased distributed PV-installed capacity is also expected to result in summer maximum system demand occurring later in the day, between 17:00 and 19:00, though the impact of distributed PV on time of maximum demand is limited beyond 19:00.

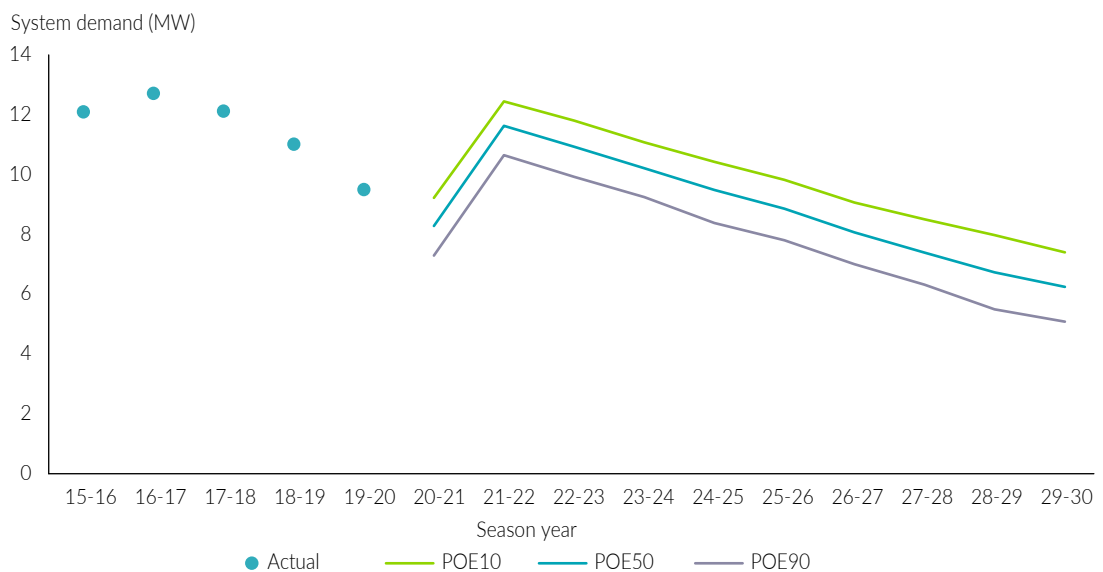
Minimum demand

Figure 17 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2015-16 to 2029-30. Over the last four years, minimum system demand has decreased as distributed PV-installed capacity grows. These distributed PV-driven minimums typically occur in the middle of the day of the shoulder season.

The forecast minimum system demand is expected to sharply rise when the JDFPG connects to the network, then continue a declining trajectory over the remaining outlook period. The rate of decrease of the POE50 forecast, after the JDFPG's connection, is 6.6% per annum. The 4.2 MW step change increase is largely influenced by the JDFPG coming online from July 2021. From 2021-22, growth in distributed PV-installed capacity is forecast to substantially decrease annual minimum system demand. Minimum system demands are forecast to occur in both shoulder and winter seasons over the outlook period, occurring consistently in the middle of the day due to distributed PV.

AEMO notes there remains a possibility of outcomes that are considered as outliers and below the POE90 minimum demand forecast, as seen in Darwin-Katherine in 2019-20.

Figure 17: Annual historical and forecast minimum system demand for Alice Springs, season years (year ending 31 August) 2015-16 to 2029-30

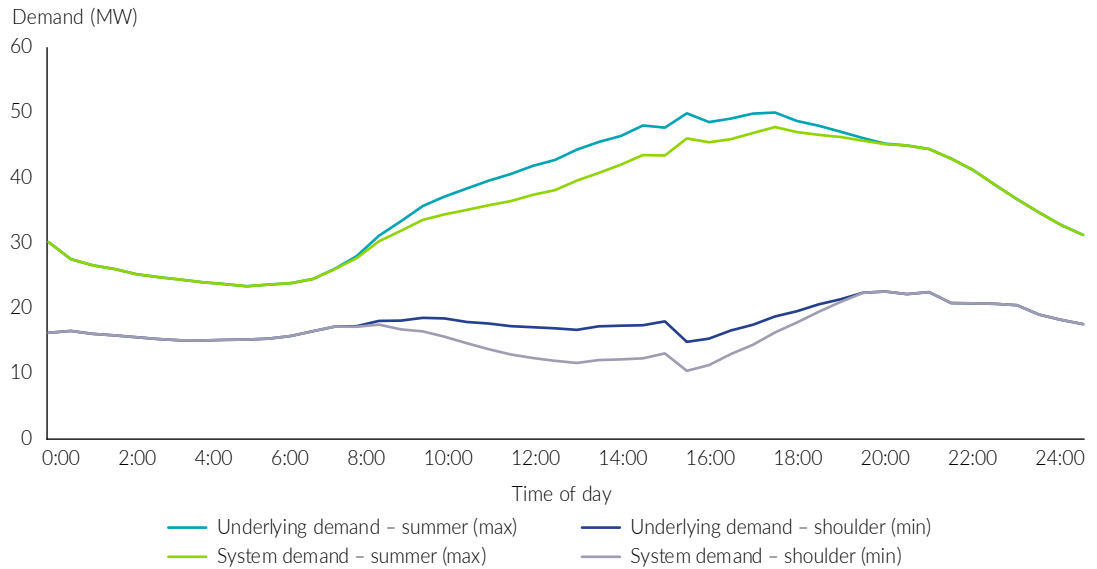


System and underlying daily load profile

Figure 18 shows typical daily load profiles, including underlying and system demand, under maximum and minimum demand conditions in the Alice Springs power system in 2019-20. System demand is consumer demand from the system (that is, demand met by large-scale network connected generators), whereas underlying demand is total energy demand at consumers' power points (that is, met by large-scale network connected generators and distributed PV). The maximum demand profile represents the average of the 10 uppermost demand values in the summer season, whereas the minimum demand profile represents the average of the 10 lowermost demand values in the shoulder season.

The light blue and green lines represent the summer season maximum underlying and system demand, respectively. The dark blue and purple lines represent the shoulder season minimum underlying and system demand, respectively. As expected, distributed PV generation during the day has lowered maximum system demand during summer. Distributed PV has lowered the daytime minimum system demand in the shoulder season to such an extent that the minimum system demand consistently occurs during the daytime.

Figure 18: Daily load profile for Alice Springs, summer and shoulder, 2019-20



Supply adequacy outlook

Key outcomes

- Expected USE in the Alice Springs power system is forecast to remain below the Commission’s adopted reliability standard of 0.002% of annual underlying energy consumption over the outlook period.
- Current planned maintenance is not expected to be a large driver of USE.
- The existing generation capacity is forecast to be insufficient to maintain system security requirements, especially after the assumed retirement of the Ron Goodin power station in July 2022¹.
- Renewable energy curtailment is forecast to continue to grow, driven by spinning reserve operational requirements and the growth in distributed PV generation.

¹ The retirement date was assumed by AEMO to be July 2022, as Territory Generation did not provide a date. July 2022 is one year later than was assumed in previous outlooks.

Unserviced energy outcomes

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). An assessment of USE, or generation adequacy assessment, is used by the electricity supply industry and the Commission to determine whether available generation capacity, including an allocation for potential outages, is sufficient to meet consumer demand (reliability). This is determined by comparing the level of forecast USE with the Commission’s reliability target of 0.002% (adopted in the absence of a formal Territory target).

The generation adequacy assessment, and following assessments in this section, did not include any assumed new generation entrants as no projects in the Alice Springs region were considered to meet the Commission’s threshold of a committed project, that is, a project with executed generation licence and relevant connection agreement with the network provider.

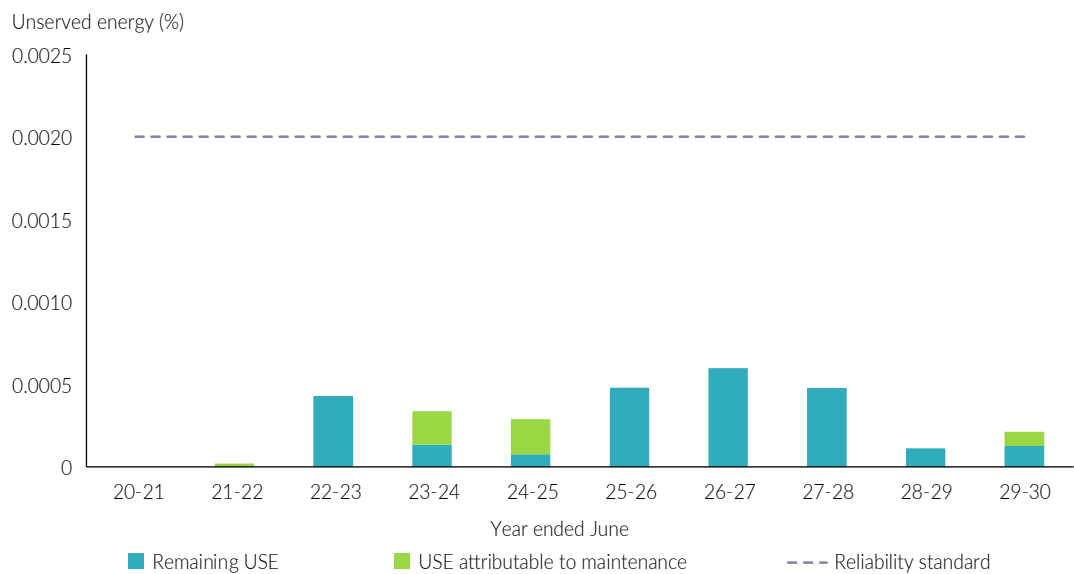
Expected USE levels are forecast to be below the Commission’s adopted reliability standard of 0.002% of annual underlying energy consumption for all years of the outlook period, as shown in Figure 19. Detailed USE forecasts are shown in Appendix B Supply details.

The main driver of expected USE is forecast concurrent unplanned outages of units at the Owen Springs power station. While infrequent, these concurrent outages are currently covered by Ron Goodin power station units, and reliability concerns emerge once these units are assumed to retire in July 2022¹⁴.

The USE forecast in this outlook is lower than that in the 2018-19 NTEOR, due to the overall reduction in forecast maximum system demand and higher forecast of distributed PV installations over the outlook period, and better coordination of planned outages.

Figure 19 shows the amount of forecast USE (blue columns), and USE caused by assumed planned outages for maintenance (green columns).

Figure 19: Forecast reliability, Alice Springs, 2020-21 to 2029-30

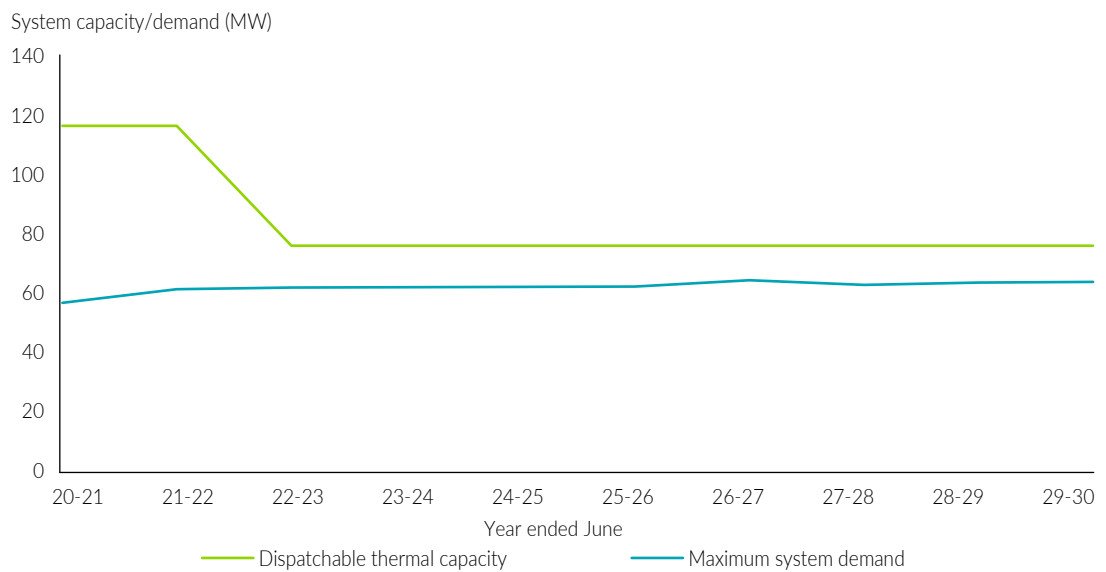


Reserve capacity

Figure 20 shows how surplus dispatchable thermal capacity declines towards the forecast ‘as generated’ summer maximum system demand following the assumed retirement of Ron Goodin power station units in July 2022¹³. The figure also shows a slight increase in forecast maximum system demand from 2021-22 after the JDFPG connects to the network.

¹⁴ The retirement date was assumed by AEMO to be July 2022, as Territory Generation did not provide a date. July 2022 is one year later than was assumed in previous outlooks.

Figure 20: Forecast summer dispatchable thermal capacity and maximum demand (POE10), Alice Springs, 2020-21 to 2029-30



Despite relatively low levels of forecast USE, the reduced amount of generation capacity reserves demonstrates the continued importance of coordinated outage planning at the Owen Springs power station and in the Alice Springs power system more generally. Suboptimal planning of scheduled outages will make the power system more vulnerable to USE events in the case of unplanned outages, as previously discussed in the 2018-19 NTEOR.

Impact of system security requirements

AEMO modelled three operational requirements in the Alice Springs power system: regulating reserve, spinning reserve and an inertia requirement (see Appendix A Methodology and assumptions for more information about the different requirements).

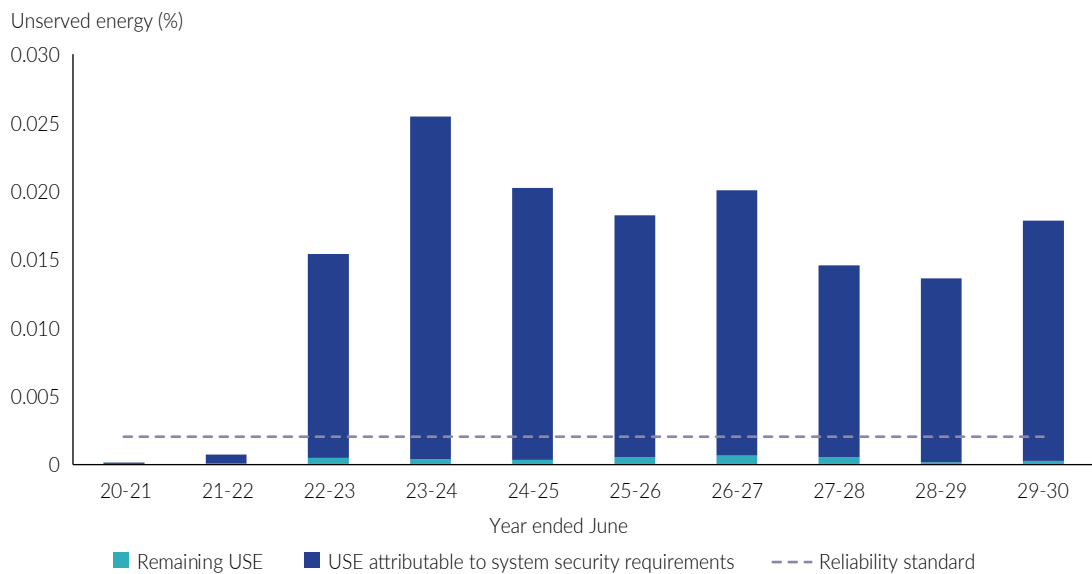
A power system should be managed to maintain reliability (that is, there is enough supply from the system to meet consumer demand) and system security (that is, minimising the risk of a major system event such as a system wide blackout). However, based on feedback provided by licensees, in practice capacity to meet system security requirements may be neglected during times when the supply-demand balance is tight to avoid disconnecting consumers. Accordingly, the above forecasts of expected USE assume numerous breaches of the system security requirements, whereas if all system security requirements were required to be maintained, forecasts of expected USE would have been much higher.

Providing the form and level of the system security requirements are appropriately determined and set by PWC System Control, AEMO notes that in not maintaining the system security requirements in order to avoid USE to some consumers, the overall power system operation may be less secure and at an increased risk of a major event, including a system black. These reliability and security trade-offs need to be carefully managed.

To highlight the impact of maintaining system security requirements, AEMO forecast the expected USE again, this time assuming the system security requirements must be maintained at all times.

Figure 21 shows forecast USE under scenarios where system security requirements are not maintained to meet demand (light blue columns), and when system security requirements are maintained to meet demand (light and dark blue columns). The 'USE attributable to system security requirements' in the figure demonstrates the impact of retaining generation capacity to meet system security requirements rather than consumer demand. Despite the power system being capable of meeting the system demand and consumption for the next 10 years, it becomes substantially short of generation capacity to maintain spinning and regulating reserve requirements following the assumed retirement of the Ron Goodin power station, highlighting emerging security and operability risks.

Figure 21: Forecast effect of strict upkeep of system security requirements in USE (%), Alice Springs, 2020-21 to 2029-30

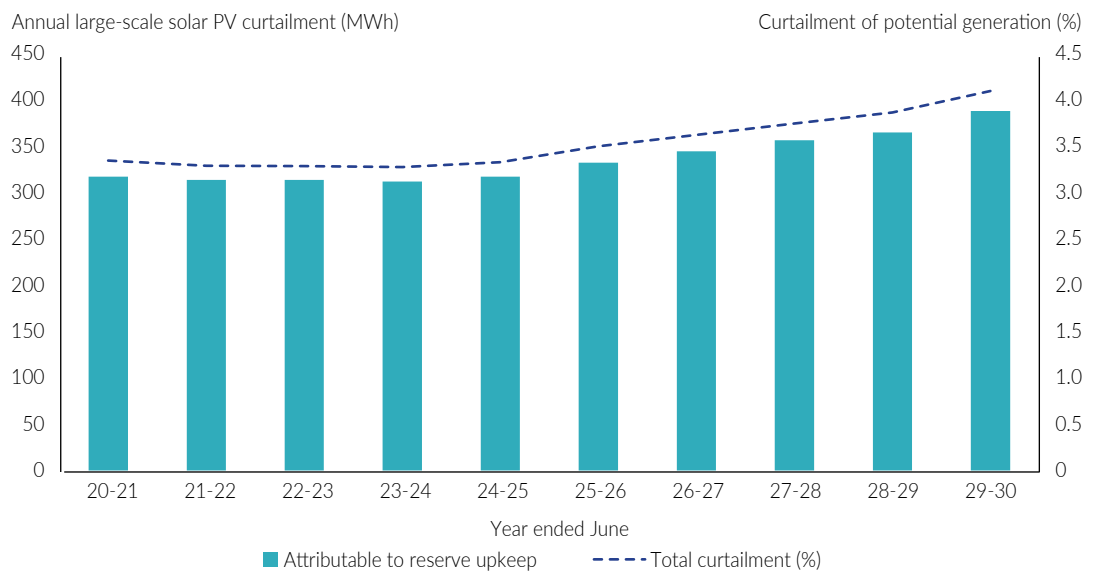


Renewable energy curtailment

Renewable energy curtailment in the Territory refers exclusively to solar PV, and specifically large-scale solar PV given the current lack of ability to curtail distributed PV. Renewable energy curtailment occurs when peak solar production coincides with low demand periods, or solar energy production needs to be curtailed in favour of thermal capacity to meet reserve and inertia requirements. Curtailment of renewable energy in the Alice Springs power system is driven primarily by the additional spinning reserve operational requirements (see Appendix A Methodology and assumptions for more detail).

The curtailment of large-scale solar PV is forecast to continue increasing each year of the outlook, as shown in Figure 22, due to the forecast growth in distributed PV installations. In the absence of strong underlying demand growth, higher distributed PV decreases system demand. Since the minimum level of thermal generation required remains unchanged, and no ability to curtail distributed PV is assumed, a reduction in system demand translates directly to a reduction in output required from large-scale solar PV generation.

Figure 22: Forecast large-scale solar PV energy curtailment, Alice Springs, 2020-21 to 2029-30



As the only large-scale solar PV generator in the Alice Springs power system, curtailment in the system refers exclusively to the Uterne solar power station and is forecast to start at 3.3% of total potential generator output in 2020-21 and increase to 4.1% in 2029-30. It should be emphasised that these values only consider the assumed security requirements listed in Appendix A Methodology and assumptions, and do not consider potential curtailment due to other requirements, such as capacity forecast errors associated with the Network Technical Code standards, or restrictions issued in a PWC System Control risk notification. Further, any future ability of the Power System Controller to curtail distributed PV has not be assumed over the outlook period.

The inertia requirement in the Alice Springs power system is adequately met by the existing thermal generation during the outlook period and not forecast to be responsible for any additional curtailment of renewable energy, beyond that attributable to the upkeep of system security requirements.

3 | Tennant Creek

This chapter focuses on the demand and supply outlook for the Tennant Creek power system over the 10-year outlook period from 2020-21 to 2029-30 and considers:

- annual and average consumption, maximum and minimum system demand, and system and underlying daily load profile
- unserved energy outcomes, reserve capacity, impact of system security requirements and renewable energy curtailment.

The outlook assumes continuation of expected growth in electricity consumption, maximum system demand, uptake of distributed residential and commercial solar PV, and includes existing and currently committed new large-scale solar PV capacity, noting none have been assumed.

Demand history and forecast

Key outcomes

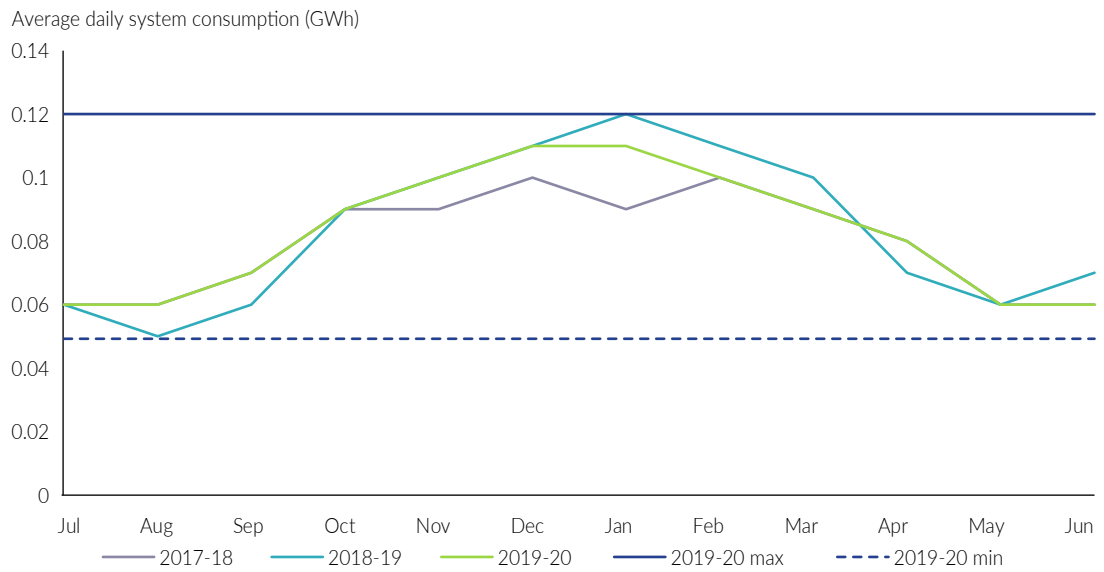
- Annual system consumption in 2019-20 was 2.8% lower than in 2018-19.
- Annual system consumption is forecast to steadily increase over the next three years before flattening after 2022-23. The initial rise in forecast annual system consumption is driven by increased system demand from a new mine development. After the site reaches full load in 2022-23, the forecast shows a slow decline, driven by negative population growth and further uptake of distributed PV.
- Maximum system demand has typically occurred in summer in the mid-afternoon, and this is expected to continue in the outlook period. Maximum system demand is expected to increase over the next three years due to the impact of a new mine development, as well as additional demand from the Northern Gas Pipeline (NGP).
- Minimum system demand has historically occurred in the shoulder season in the early morning, although winter minimums have been at very similar levels. The forecast of minimum system demand in Tennant Creek is expected to increase over the first three years of the outlook period due to a new mine development but then remains relatively flat after this project reaches full production. The forecast levels of shoulder and winter minimums are expected to be very similar over the outlook period.

Annual and average consumption

Levels in 2019-20

In 2019-20, total system consumption in the Tennant Creek power system was 29.6 GWh, which is a 2.8% reduction from 2018-19. Figure 23 shows the average daily system consumption by month over the past three financial years in the Tennant Creek power system. Average daily system consumption in 2019-20 was 0.08 GWh, and maximum and minimum daily consumption was 0.12 GWh and 0.05 GWh, respectively. The variability of consumption reflects the fact that Tennant Creek experiences wide temperature changes between seasons.

Figure 23: Average daily system consumption for Tennant Creek by month, 2017-18 to 2019-20



Forecast

Figure 24 shows historical and forecast annual system consumption in the Tennant Creek power system from 2015-16 to 2029-30. Annual system consumption is forecast to increase for the first three years to 2022-23 at a compound average growth rate of 6.4% due to a new mine development. From 2022-23, annual system consumption is forecast to decline at a rate of -0.1% per annum. The decline is a result of expected population decline prior to 2026-27, and growth (albeit slow) in residential distributed PV that reduces system demand.

Figure 24: Historical and forecast annual system consumption for Tennant Creek, 2015-16 to 2029-30

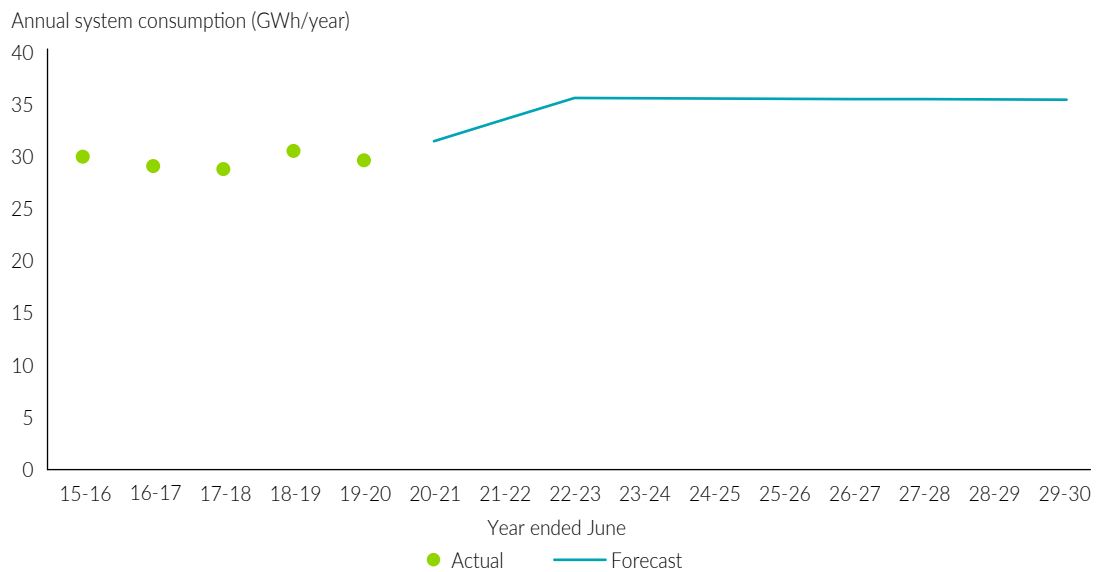
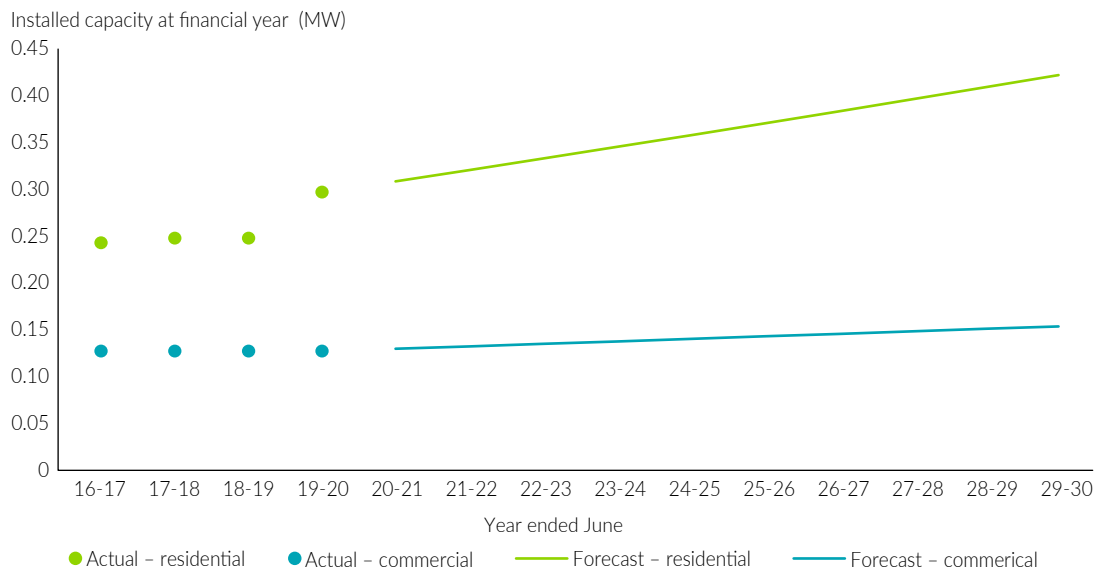


Figure 25 shows the historical and forecast distributed PV-installed capacity for Tennant Creek from 2016-17 to 2029-30.

Figure 25: Historical and forecast distributed PV capacity, Tennant Creek, 2016-17 to 2029-30

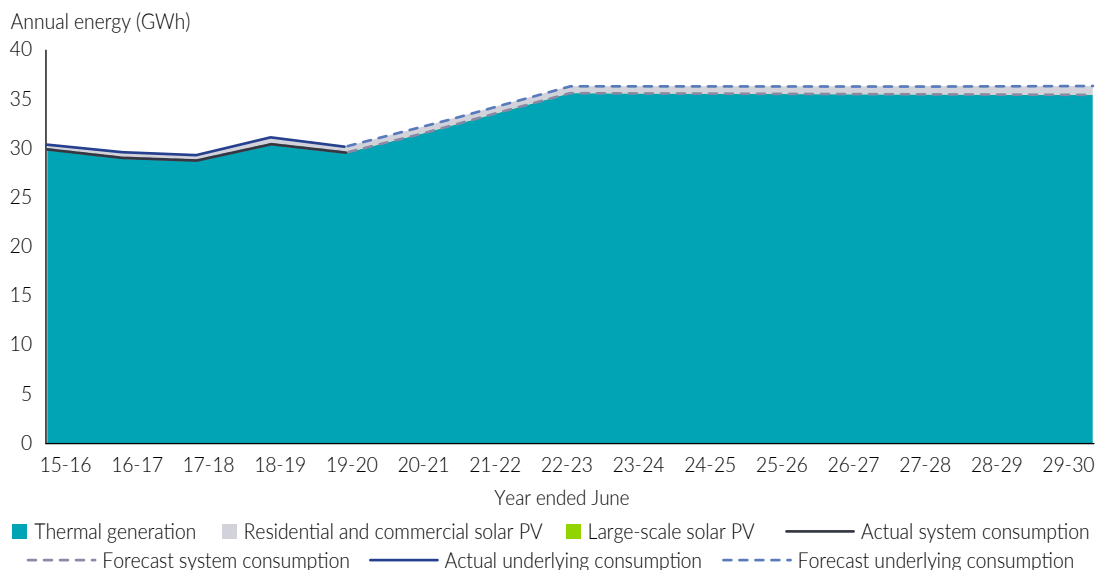


Historically, the rate of installation of distributed PV in the Tennant Creek region has been very low. The step change in 2019-20 is likely attributable to recent changes in incentives. The forecasts of distributed PV are higher compared with last year, reflecting a trend seen in distributed PV forecasts in other parts of Australia. Although higher, distributed PV-installed capacity is still very small with respect to system demand compared with Darwin-Katherine and Alice Springs.

As of June 2020, actual residential and commercial distributed PV capacity in Tennant Creek totalled 0.3 MW and 0.1 MW, respectively. By 2029-30, residential commercial distributed PV capacity is forecast to increase to 0.4 MW and 0.2 MW, respectively.

Figure 26 shows historical and forecast annual system consumption supplied by different generation categories in the Tennant Creek power system from 2015-16 to 2029-30.

Figure 26: Historical and forecast consumption met by generation types for Tennant Creek, 2015-16 to 2029-30



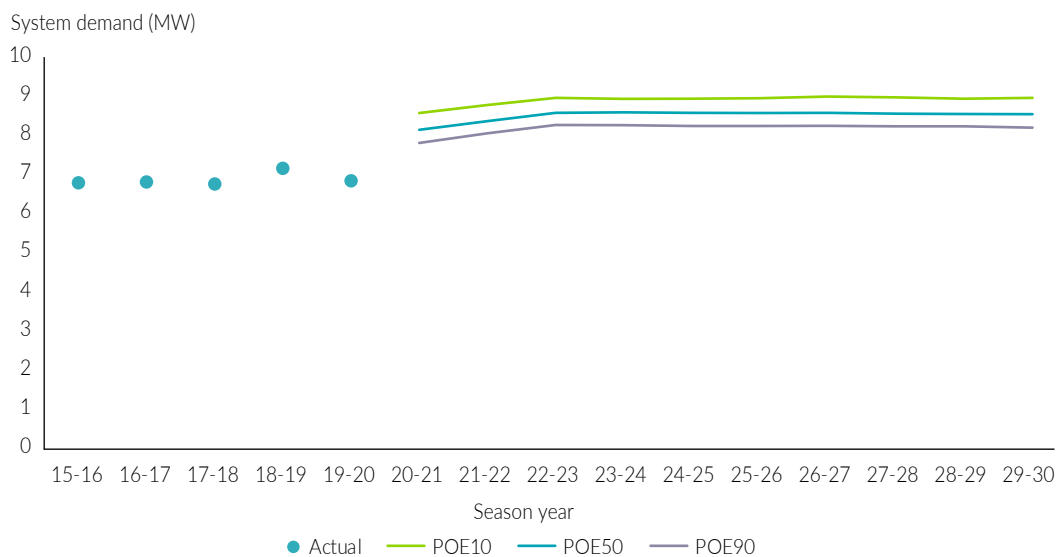
This assessment only includes existing generators and may be impacted by any new generator commitments. The forecast contribution from all types of solar PV generation to meet consumer demand is minimal. By 2029-30, the generation from residential and commercial solar PV is forecast to meet 2.43% of the underlying consumption.

Maximum demand

Figure 27 shows historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels for Tennant Creek from 2015-16 to 2029-30. Maximum system demand has historically occurred in the mid-afternoon during summer, between 14:30 and 15:30. Due to minimal changes in population and modest distributed PV growth forecasts, maximum system demand is forecast to occur at a similar time of day, between 13:30 and 15:30.

The maximum system demand forecast indicates a step change from the 2019-20 observed maximum to one that is about 0.9 MW higher, with additional growth over the following two years. This step change is mostly the result of a new mine development staged over three years, starting July 2021 (see Table 3 in Appendix A Methodology and assumptions). Additionally, the assumption for maximum demand is that the NGP's compressors and alternators are drawing power from the system during summer¹⁵. From 2022-23 to the end of the outlook period, the maximum system demand is forecast to remain flat.

Figure 27: Historical and forecast maximum system demand for Tennant Creek, season years (year ending 31 August) 2015-16 to 2029-30



Minimum demand

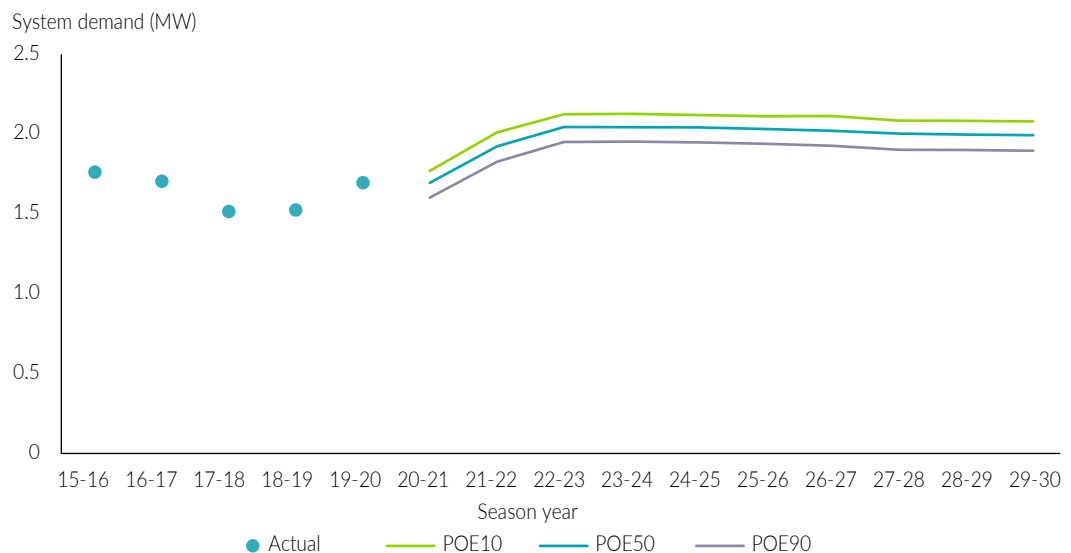
Figure 28 shows historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Tennant Creek power system from 2015-16 to 2029-30. Minimum system demand has occurred overnight in the shoulder season, in either May or September, for four of the past five years, with winter season minimums at similar levels and at a similar time of day.

¹⁵ System demand from the NGP is expected to be infrequent due to the gas normally being used to power the compressors and gas engine alternators.

The level of minimum system demand is forecast to increase for the first three years of the outlook before decreasing marginally, with the POE50 forecast decreasing at a rate of 0.36% per annum over this period. The initial increase is mostly a result of a new mine development staged over three years starting July 2021 (see Table 3 in Appendix A Methodology and assumptions). The forecast minimums predominantly occur in winter over the outlook period, with the time of day a mixture of early morning and midday. Distributed PV is forecast to grow at a lower rate over the outlook compared with other regions. As a result, there is no clear shift from early morning to midday minimums during the outlook period. The NGP compressors and alternators are assumed not to be drawing load during periods of minimum demand.

AEMO notes there remains a possibility of outcomes that are considered outliers and below the POE90 minimum demand forecast, as seen in Darwin-Katherine in 2019-20.

Figure 28: Historical and forecast minimum system demand for Tennant Creek, season years (year ending 31 August) 2015-16 to 2029-30

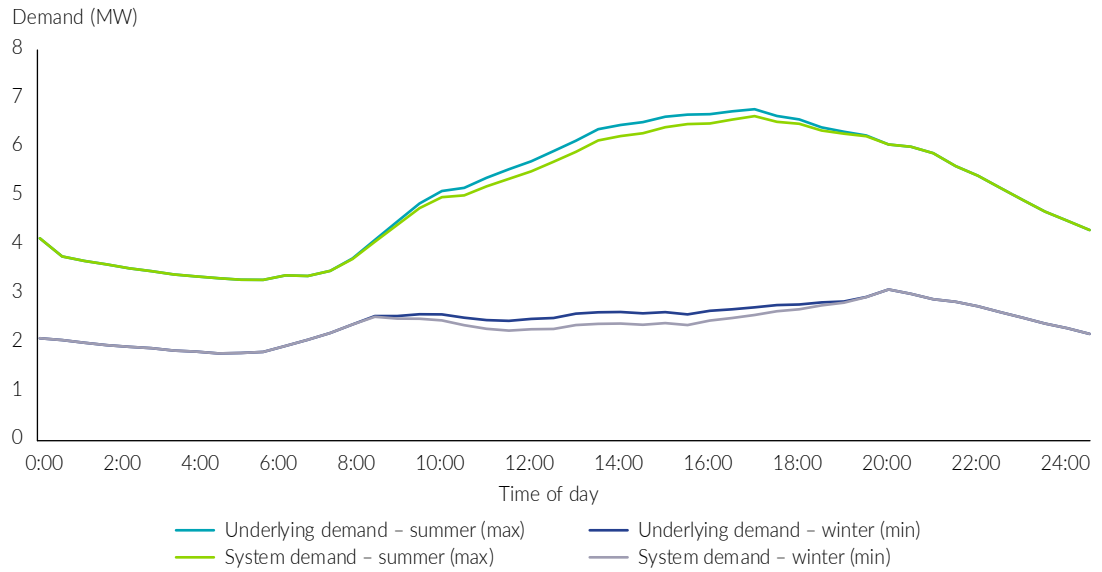


System and underlying daily load profile

Figure 29 shows typical daily load profiles, including underlying and system demand, under maximum and minimum system demand conditions in the Tennant Creek power system for 2019-20. System demand is consumer demand from the system (that is demand met by large-scale network connected generators), whereas underlying demand is total energy demand at consumers' power points (that is met by large-scale network connected generators and distributed PV). The maximum demand profile represents the average of the 10 uppermost demand values in the summer season, whereas the minimum demand profile represents the average of the 10 lowermost demand values in the winter season.

The light blue and green lines represent the summer season maximum underlying and system demand, respectively. The dark blue and purple lines represent the winter season minimum underlying and system demand, respectively. Distributed PV generation during the day has lowered maximum system demand in summer. While distributed PV has also lowered the daytime minimum system demand in winter, the overall minimum system demand still occurs overnight.

Figure 29: Daily load profile for Tennant Creek, summer and winter, 2019-20



Supply adequacy outlook

Key outcomes

- Generation capacity is forecast to be sufficient to meet the Commission’s adopted reliability standard, and assumed system security requirements.
- There are no material capacity shortages for the provision of system security requirements forecast, and no USE is forecast in the Tennant Creek power system over the outlook period.

Unserviced energy outcomes

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). An assessment of USE, or generation adequacy assessment, is used by the electricity supply industry and the Commission to determine whether available generation capacity, including an allocation for potential outages, is sufficient to meet consumer demand (reliability). This is determined by comparing the level of forecast USE with the Commission’s reliability target of 0.002% (adopted in the absence of a formal Territory target).

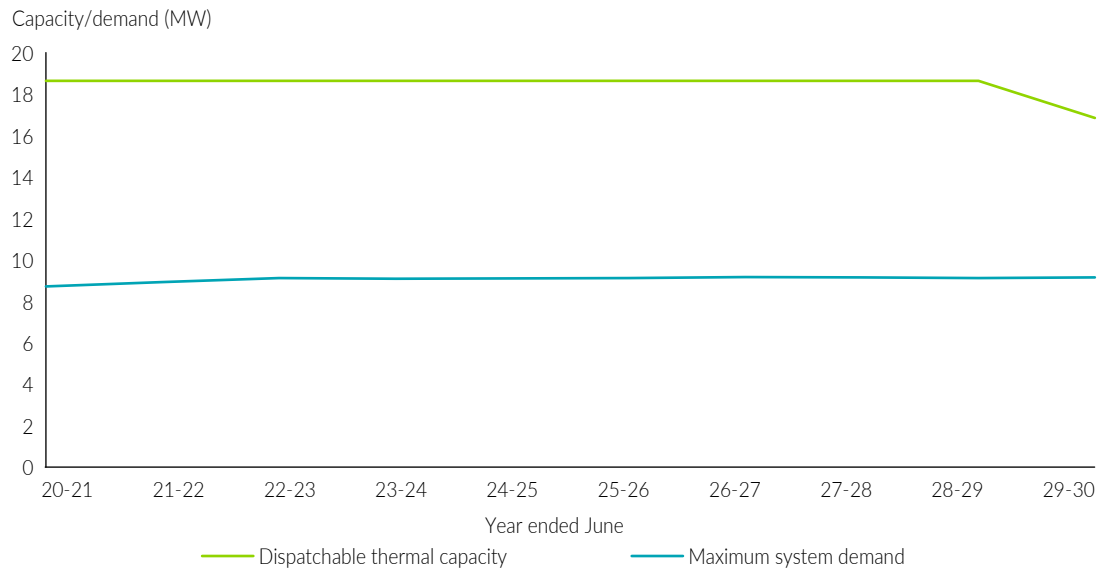
The generation adequacy assessment, and following assessments in this section, did not include any assumed new generation entrants. This is because no projects in the Tennant Creek region were considered to meet the Commission’s threshold of a committed project. The Commission defines a committed project as a project with an executed generation licence and relevant connection agreement with the network provider.

No USE is forecast in the Tennant Creek power system across the entire outlook period, due to surplus generation capacity (see Appendix A Methodology and assumptions). However, there remains a possibility that USE could occur due to coincident outages across many generating units, noting that multiple contingency events have occurred in the past. Detailed USE forecasts are shown in Appendix B Supply details.

Reserve capacity

As shown in Figure 30, the Tennant Creek power system has a substantial level of reserve capacity when compared with the forecast summer maximum system demand. This results in almost no USE forecast and minimal impacts if system security requirements were maintained at all times.

Figure 30: Forecast summer dispatchable thermal capacity and maximum demand (POE10), Tennant Creek, 2020-21 to 2029-30

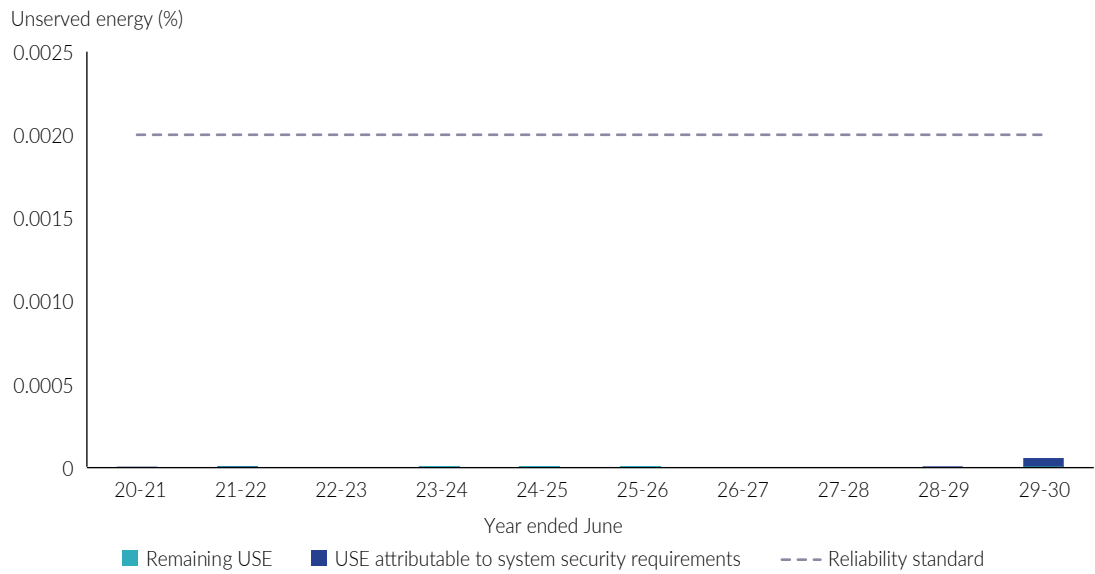


Impact of system security requirement

The available installed generation capacity in the Tennant Creek power system is more than adequate to meet the current system security requirements. Only in the last year of the outlook period, after Tennant Creek power station units 10 to 13 are assumed to retire, were any forecast system security requirement impacts identified.

Figure 31 shows forecast USE under scenarios where system security requirements are not maintained to meet consumer demand (light blue columns) and when system security requirements are maintained to meet demand (light and dark blue columns).

Figure 31: Forecast effect of strict upkeep of system security requirements in USE (%), Tennant Creek, 2020-21 to 2029-30



No inertia requirement was modelled for the Tennant Creek power system.

Renewable energy curtailment

There are no existing or committed large-scale solar PV generation projects in the Tennant Creek power system.

Appendices

A | Methodology and assumptions

This appendix presents the methodology and assumptions used in the 2020 NTEOR, and should be read and considered in conjunction with any outcomes, conclusions and recommendations made in this publication.

AEMO and the Commission undertook consultation on the methodology and assumptions proposed for use in the 2020 NTEOR. This consultation occurred in November and December 2020 and provided an opportunity for both written and verbal feedback on the proposed assumptions. Feedback was received from five licensees, one Territory Government department and the Commission. The methodology and assumptions used in the NTEOR have been refined based on this consultation and final assumptions are documented in this appendix, by forecast component. Components discussed include:

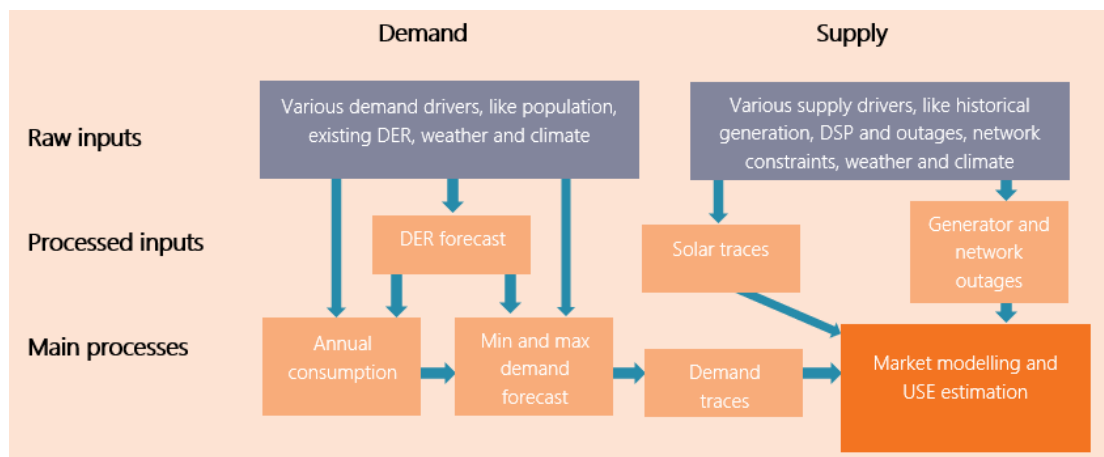
- annual energy consumption
- maximum and minimum demand
- demand traces
- generator supply
- transmission and power system security
- supply adequacy.

Forecast components

Production of AEMO's high level outputs requires multiple sub-forecasts to be produced and appropriately integrated; these are referred to as forecast components. Figure 32 shows the forecast components used in this process. AEMO's NEM methodology documents explain some of these processes in more detail¹⁶.

In Figure 32, inputs can be seen as data streams (including forecasts provided by third parties) used directly in AEMO's forecasting process. For the NTEOR, AEMO employs a simplified process that is broadly aligned with the NEM approach. Simplifications and deviations from the NEM process are described in this appendix.

Figure 32: Forecasting components



¹⁶ These documents are available at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines>.

Scenarios and uncertainty

There are two types of uncertainties in AEMO's forecasts:

- structural drivers, which are modelled as scenarios, including considerations, such as population and economic growth, and uptake of future technologies, including distributed PV, batteries and electric vehicles
- random drivers, which are modelled as a probability distribution and include weather drivers and generator outages.

The electricity industry in the Territory, like elsewhere in Australia, is experiencing a rapid transformation, in particular driven by large growth in the installation of distributed PV systems on residential and commercial premises.

The 2020 NTEOR focuses on a single business-as-usual scenario: exploring, in detail, the challenges and opportunities that will arise without further actions by government and investors. This is consistent with the 2018-19 NTEOR. Previous NTEORs focussed on a multiple scenario approach, which included a scenario of achieving 50% renewable energy consumption in the Territory's three regulated power systems by 2030. The single business-as-usual scenario approach was adopted for a number of reasons, which remain valid for the 2020 NTEOR. These include:

- the challenges associated with the Territory relying on solar PV and battery storage alone to provide a significant portion of its electricity consumption in the three regulated systems from renewable energy sources. To achieve a significant portion of the Territory's electricity consumption without compromising the reliability and quality of electricity supply, it is likely to require a mix of other technologies, which are beyond the scope of the NTEOR
- the Commission considering it more of a priority to assess and explore in detail the business-as-usual scenario, including the challenges, gaps and opportunities that will arise from the ongoing transformation, with the scenario assuming the continuation of current trends, and existing and currently committed new large-scale generation.

The business-as-usual scenario assumes:

- expected growth in electricity energy consumption and maximum demand
- expected uptake of distributed PV, including rooftop and small behind-the-meter PV installations, based on continuation of current trends, and known policies
- existing and currently committed new large-scale thermal and solar PV generators, and large-scale batteries
- scheduled generator decommissioning provided by licensees
- best representation of the current power system security constraints.

For the random drivers, a probability distribution of their outcomes can be estimated, particularly probability distributions that represent uncertainty in consumer maximum demand, generator forced outage profiles and USE.

This outlook does not explicitly take into account the impacts COVID-19 may have on electricity consumption or maximum and minimum demand. COVID-19 is not expected to materially impact Territory consumption and demand in the medium term.

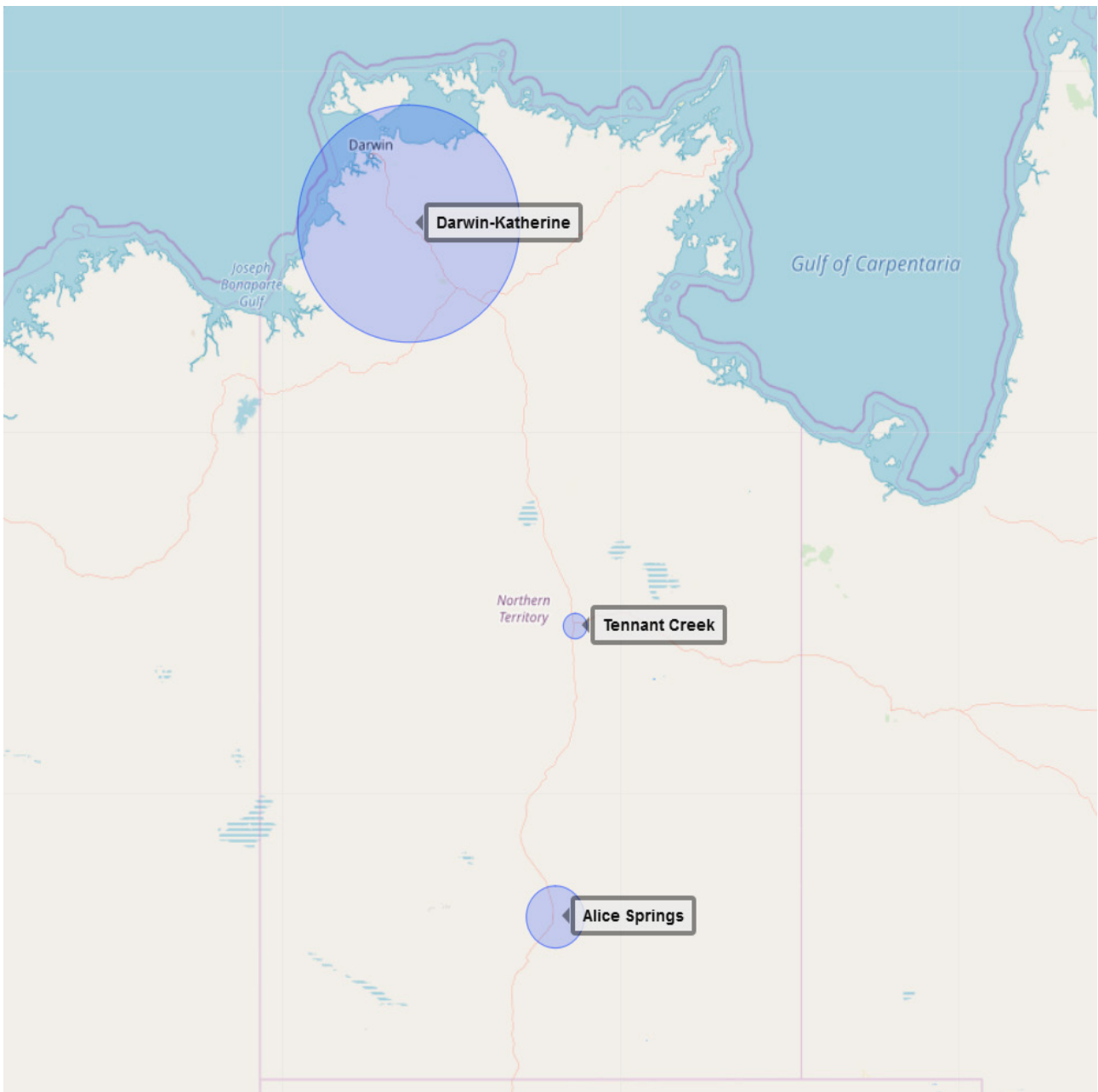
Northern Territory power systems

The three regulated power systems in the Territory are:

- Darwin-Katherine
- Alice Springs
- Tennant Creek.

These three power systems are not connected to each other, with the general location of each system within the Territory shown in Figure 33. Isolated systems in remote communities not connected to one of the three regulated power systems are not considered in this outlook.

Figure 33: Spatial representation of three regulated power systems in the Northern Territory



Annual energy consumption methodology

The annual energy consumption forecasts are designed to capture the main actual and expected drivers in electricity consumption and trends over the 10-year outlook period.

The foundation of the annual energy consumption forecast is a weather-based regression model, used to create a 'base year' forecast that represents the consumption in a year with typical weather conditions. The model is built using daily system consumption data and weather data from Bureau of Meteorology (BOM) stations in close proximity to the Territory's consumption centres.

The base year is then projected forward on an annual basis, applying projected growth in population and uptake of distributed PV generation.

As with the previous outlooks, gross state product (GSP) was not used as a growth driver in the forecasts. Statistical analysis suggests its correlation with energy consumption in the Territory remains weak.

Large load variations representing changes in industrial consumption are included as step changes in the consumption forecasts. Block load assumptions used in consumption, and maximum and minimum demand forecasts are described in this appendix.

Maximum and minimum demand methodology

For forecasting maximum and minimum demand, AEMO has applied a regional demand forecasting methodology, in line with models AEMO uses in forecasting for the NEM¹⁷.

The main difference between current NEM and Territory demand forecasting is the NEM models have been supplemented by the outcomes of a generalised extreme value model, which helps focus the half-hourly model and tends to narrow the range of distribution. This has not yet been implemented by AEMO for the Territory power system forecasts.

The methodology used for the Territory forecasts provides probabilistic demand forecasts by season as demand is dependent on weather conditions (primarily temperature) and includes a degree of stochastic variability, because these conditions vary from season to season, as well as year to year.

Due to this variability, maximum and minimum demand forecasts are expressed as POE values from a distribution, rather than a point forecast. For any given season or season year (year ending 31 August):

- a POE10 maximum demand value is expected to be exceeded, on average, one year in 10
- a POE50 maximum/minimum value is expected to be exceeded, on average, one year in two
- a POE90 minimum demand value is expected to be exceeded, on average, nine years in 10, that is, actual minimum demand is expected to be lower than the POE90 minimum demand for, on average, one year in 10.

¹⁷ See Electricity Demand Forecasting Methodology Information Paper, August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

Demand assumptions

Demand definitions

In this methodology, 'system demand' is defined as the power sent into the network by licensed in-front-of-the-meter generators in the three regulated power systems, and is expressed in MW:

- for Darwin-Katherine, generation from:
 - Channel Island, Weddell, Pine Creek, Shoal Bay, and Katherine power stations
 - the new large-scale generation of Eni Australia Limited's Katherine, Batchelor, and Manton solar farms, and the Merricks Capital Group's Batchelor 2 Solar Farm and Hudson Creek power stations¹⁸
- for Alice Springs, generation from:
 - Ron Goodin and Owen Springs power stations
 - Uterne solar farm
 - the system-level BESS connected at the Sadadeen substation. The BESS was not considered a supply source for the purpose of supply adequacy modelling because it is understood to have been installed primarily to compensate for low inertia of the new reciprocating generators at the Owen Springs power station by providing fast regulation. However, AEMO notes PWC System Control has advised that the impact of the BESS in relation to its inertia contribution has not been quantified and therefore, for the purpose of the modelling, it was excluded from contributing to the assumed minimum inertia requirement. Accordingly, the BESS was only included in system demand to ensure all actual energy (charging and discharging) is accounted for. Due to its limited energy storage capability, it is unlikely to affect half-hourly maximum and minimum demand
- for Tennant Creek, generation from:
 - Tennant Creek power station, recorded at transformers 3 and 4¹⁹. Secondly, the sum of feeders if data quality necessitates an alternative source of demand data.

System demand excludes generator auxiliary load (electricity used on site by the generator).

Similarly, system consumption is defined as energy generated by licensed in-front-of-the-meter generators in the three regulated power systems and is expressed in megawatt hours (MWh).

Demand modelling has been performed on underlying demand, which is an estimate of all the power used by consumers from the power point, from any source (including both the system and distributed PV installed by residential or commercial consumers). This produces a tight relationship between demand and weather, allowing the impact of distributed PV to be modelled separately. Distributed PV impacts can then be coupled to the underlying demand model results inside the simulation engine to derive system demand. Underlying

¹⁸ Although Eni's Katherine, Batchelor and Manton solar power stations, and the Merricks Capital Group's Batchelor 2 Solar Farm and Hudson Creek power stations, are not yet in commercial operation, they are considered to be committed projects as they have an executed generation licence and relevant PWC access agreement.

¹⁹ Metering points for Tennant Creek demand data in this year's outlook changed from the sum of generation to the substation load, which supplies the distribution network. This reflects a lowering of up to 10%, attributed to primarily on-site power station consumption.

consumption refers to underlying energy consumed calculated similarly to underlying demand and is expressed in MWh.

Season definitions

The demand forecasts are modelled at the season level and presented as a season year (year ending 31 August):

- summer season (wet, in the case of Darwin-Katherine), is defined as 1 November to 31 March
- winter season (dry, in the case of Darwin-Katherine) is defined as 1 June to 31 August
- shoulder season is defined as the months September, October, April, and May.

Following stakeholder consultation regarding the 2020 NTEOR, AEMO consulted with the BOM in relation to the above seasonal definitions but did not identify a need to revise the definitions from a climate perspective.

Demand simulations are performed across forecast years using the seasonal model appropriate to the time of year. Probabilistic forecasts are derived from this set of simulations, partitioned into season years, where season years are between 1 September and 31 August. The supply adequacy assessments and input demand traces are however developed on a financial year basis.

Demand data and network information

PWC Power Services provided:

- demand data, which is used to conduct historical analysis and construct forecasting models. It includes half-hourly data at the zone substations, in addition to system level demand
- network information on outage events, used to assist in cleaning historical demand data
- information about industrial demand changes, future load transfers, and anticipated new load
- a record of distributed PV installations.

Economy and population

Forecasts of population, summarised in Table 2, are based on five-year long-term averages using Australian Bureau of Statistics (ABS) statistical area information. Population growth rates have been developed using population projections from the Territory Government's Department of Treasury and Finance. The population trajectories are intended to represent long-term growth trajectories²⁰.

²⁰ Relevant projections can be found at <https://treasury.nt.gov.au/df/economic-group/population-projections>.

Table 2: Population growth rates adopted for demand forecast

	Population growth rate (per annum) (%)			ABS statistical areas
	2018-19 to 2020-21	2021-22 to 2025-26	2026-27 to 2030-31	
Darwin-Katherine	0.68	1.30	1.69	Greater Darwin (SA4) and Katherine (SA3)
Alice Springs	0.27	0.56	0.58	Alice Springs (SA3)
Tennant Creek	- 0.86	- 0.39	0.11	Barkly (SA3)

Forecast GSP is available for the Territory but, as noted earlier in this appendix, it has not been adopted as an indicator of energy consumption for the three regulated power systems. Statistical tests have verified that GSP is not directly indicative of economic activity in Tennant Creek and Alice Springs, nor of energy consumption in the Darwin-Katherine region due to liquefied natural gas projects that contribute significantly to GSP but consume relatively little or no energy from the network.

Block load changes

Significant load changes explicitly modelled in the annual consumption, maximum and minimum demand forecasts are described in Table 3. These block loads have been provided by PWC as being likely to connect or disconnect over the outlook period and exclude loads otherwise captured by drivers such as population.

Key sites featured in the forecasts are:

- in Darwin-Katherine, operations at Cosmo mine ceased in March 2020 and this site is not assumed to return as a significant load in the outlook period
- in Alice Springs, the existing JDFPG is expected to connect to the network in the 2021-22 financial year
- a mine development in Tennant Creek is expected to impact demand incrementally over the 2020-21, 2021-22, and 2022-23 financial years.

Table 3: Block assumptions for annual consumption, maximum and minimum demand

Power system	Site	Effective date	Status
Darwin-Katherine	Cosmo mine	1/7/2020	Disconnect
Alice Springs	JDFPG	1/7/2021	Connect
Tennant Creek	Mine development	1/7/2020	Connect
Tennant Creek	Mine development	1/7/2021	Connect
Tennant Creek	Mine development	1/7/2022	Connect

Residential and commercial PV

Installed solar PV capacity is split into residential, commercial, and large-scale (network-connected) solar PV:

- residential and commercial solar PV systems (referred to as distributed PV) offset the demand met by system demand
- large-scale solar PV systems operate as system generators and therefore contribute to system-supplied energy. This is discussed in the Supply assumptions section of this appendix.

Historical records of residential and commercial solar PV systems are provided by PWC and used as a foundation for the distributed PV forecasts. Future changes to PWC's Embedded Generation policy²¹ are not included in the 2020 NTEOR due to insufficient data and information to determine the impact of the policy with respect to solar PV system sizes. No limits on exports of distributed PV generation to the network are imposed. The modelling of zero-export systems is considered by AEMO to be very complex and further data and advice from PWC would be required. Additionally, distributed PV is not assumed to be curtailable under emergency situations.

The PV forecasts are based on the following assumptions:

- For residential systems:
 - In April 2020, the Territory Government changed Jacana Energy's (which has the majority of customers in the Territory) solar PV incentive framework by replacing the premium one-for-one feed-in tariff with 8.3c/kilowatt hour (kWh) for new installations, new customers with existing installations, and existing customers that make changes to their existing installation. At the same time, the Territory Government announced a battery storage subsidy for residential and commercial installations. Anticipating the reduction of the tariff incentive, along with the conclusion of the Northern Territory Home Renovation Grant, 2019-20 saw a significant boost to distributed PV installations. Since the winding back of these programs, the rate of installation of distributed PV installations has slowed down. AEMO is forecasting a rebound in installations towards the end of 2020-21 and onwards. The rebound is driven by analysis of other jurisdictions where the feed-in tariff has reduced, such as in South Australia in 2011. Further, the rate of distributed PV installations has been increasing across all of Australia regardless of feed-in tariff.
 - The forecast rate of installations in Darwin-Katherine is estimated from the average rate of installation from 2016-17 to 2019-20. This period includes elevated rates of installations, especially in the last two years, attributed to multiple incentives to install distributed PV systems, including the Commonwealth Government's Small Scale Renewable Scheme, Northern Territory Smart Energy Grants (closed in October 2018), and Northern Territory Home Renovation Grants (closed on 30 November 2020), coupled with high solar feed-in tariffs. By taking the average over the last four years, the forecast rate of installation is moderated relative to this elevated period to reflect the winding back of a number of these incentive schemes. In addition, the value is tapered further in Darwin-Katherine and Alice Springs during the later stages of the outlook period to capture the effects of saturation by ensuring installation rates relative to the estimated number of remaining dwellings without solar PV systems remain approximately constant.

²¹ See PWC's consultation document on changes to the Embedded Generation policy: <https://www.powerwater.com.au/customers/power/solar-power-systems/pv-class-requirements>.

- Modelling has assumed that 85% of new dwellings have solar PV systems installed throughout the outlook period, and installations on existing dwellings will continue at current rates. Following stakeholder consultation regarding the 2020 NTEOR, the percentage of new dwellings installing solar PV systems was revised down from 95% (in previous NTEORs) to 85%. While the percentage is not data driven, AEMO considers it to be suitable. The materiality of this assumption is low as existing commercial and residential dwellings dominate the distributed PV-installed capacity forecasts. The base estimate of total residential installation rate for the 2020 NTEOR for Darwin-Katherine is 1,961 per year (recent years have ranged from 1,329 to 2,894). The adopted rate for Alice Springs is 249 per year (recent years have seen installation rates in the range of 163 to 322), and for Tennant Creek it is two per year (recent years have mostly seen installation rates in the range of zero to seven).
- Residential system totals represent the sum of systems reported by PWC Power Services as having the classification 'private'.
- For commercial systems:
 - Installations have been assumed to continue at rates resembling those seen in the years preceding 2020-21 (85 installations per year in Darwin-Katherine, 14 per year in Alice Springs, and 1 per 30 months in Tennant Creek). This is supported by almost constant installation rates seen in recent years. For the Darwin-Katherine power system, modelling adopted the 2019-20 average installed capacity for new commercial systems. This approach is adopted because it reflects the recent decline in system size without forecasting ongoing decline as seen over the past four years.
 - For Alice Springs and Tennant Creek, where greater variability is observed compared with Darwin-Katherine, modelling has used data from earlier years (average between 2015-16 and 2019-20).
 - Commercial system totals represent the sum of systems reported by PWC Power Services as having the classification 'commercial'.
- For large-scale solar PV systems:
 - Existing and future systems were considered to contribute to meeting system demand and were modelled on the supply side, not the demand side. These systems are discussed in the Supply assumptions section of this appendix.

Distributed PV generation has been derived using half-hourly estimates of generation for each power system normalised to a kW (output) per kW (installed capacity) basis.

As with the 2018-19 NTEOR, AEMO has used a third-party provider to deliver normalised distributed PV generation estimates.

Behind-the-meter battery storage

As of November 2020, there were about 300 applications for behind-the-meter batteries as part of the Territory Government's Home and Business Battery Scheme²². Advice from PWC indicates these batteries are not likely to have a material impact on system demand currently or in the immediate outlook period. There are also numerous small-scale virtual power plants proposed, including those from RPS1101 Pty Ltd and a trial from Desert Knowledge Australia.

²² See <https://newsroom.nt.gov.au/mediaRelease/33941>.

Given the low quantity of current or likely future installations, relative to system size, behind-the-meter batteries and virtual power plants are assumed to be immaterial for this supply adequacy assessment, and have been excluded. This assumption may require further consideration in future assessments, subject to a change in expected installation rates.

Half-hourly demand traces

Demand traces (referred to as demand time-series in general terms) have been prepared by deriving a trace from a historical reference year (financial-year) and growing (scaling) it to meet specified future characteristics. This was achieved through a constrained optimisation function that minimises the differences between the grown trace and the demand targets.

The Territory demand traces have been grown using a similar methodology to the one AEMO adopts for the NEM²³.

The traces have been prepared on a financial-year basis, to various targets, categorised as:

- maximum summer demand (at a specified POE level)
- maximum winter demand (at a specified POE level)
- minimum demand (at a specified POE level)
- annual energy (consumption).

Traces have been differentiated by:

- Territory region
- target year
- POE level.

The trace development process has been conducted in two passes for each combination of the Territory region, historical reference year, target year and POE level:

- pass 1 – growing the reference year (observed) trace on an underlying demand basis to meet underlying targets
- pass 2 – reinstate forecasts of technology components and reconcile the time series to meet the forecast targets.

Demand side participation

No demand side participation is currently used in Territory regions and this has been assumed to persist over the outlook period.

Supply assumptions

This section explains the assumptions used to model the supply system in each of the three regulated power systems in the Territory. The model was used to undertake simulations of future dispatch outcomes to assess power system reliability.

²³ See Electricity Demand Forecasting Methodology Information Paper, August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

Power station parameters

The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Table 4 outlines the key parameters used and describes how they were incorporated in the reliability modelling. Inputs and assumptions were based on information provided by licensed generators.

Table 4: Summary of generator technical parameters

	Description
Maximum capacity	Nameplate capacity of each generating unit.
Rating	Reflects the impact of seasonal temperature on generator available capacity. This value overrides the maximum capacity.
Minimum stable level	Minimum stable load for generation.
Outage schedule	Planned outage schedule of units. AEMO applied the 10-year outage plan provided by licensed generators.
Outage rates	Historical unplanned failure rates that describe the probability of capacity duration of each technology.
Mean time to repair	Average time required to repair a failed unit and return it to normal operating conditions.

Power station retirements

Based on information provided by licensed generators, or assumed by AEMO where a licensee did not provide a date, AEMO modelled the retirement of generating units at the Ron Goodin, Tennant Creek, Channel Island, and Katherine power stations. Table 5 shows the retirement dates used in the simulation and the units that have been recently retired, which were not included in the 2020 NTEOR supply adequacy assessment.

Table 5: Power station retirements

Power station	Power system	Unit	Main fuel type	Estimated summer capacity (MW)	Assumed retirement date		
Ron Goodin power station ¹	Alice Springs	3	Gas	3.99	July 2022		
		4	Gas	3.99	July 2022		
		5	Gas	3.99	July 2022		
		6	Gas	5.23	July 2022		
		7	Gas	5.23	July 2022		
		8	Gas	5.23	July 2022		
		9	Gas	12.83	July 2022		
		Tennant Creek power station	Tennant Creek	1	Diesel	1.14	Retired
				2	Diesel	1.14	Retired
3	Diesel			1.14	Retired		
4	Diesel			1.14	Retired		
5	Diesel			1.14	Retired		
10	Gas			0.90	31 December 2028		
11	Gas			0.90	31 December 2028		
12	Gas			0.90	31 December 2029		
13	Gas			0.90	31 December 2029		
Channel Island power station	Darwin-Katherine	1	Gas	30.02	31 December 2026		
		2	Gas	30.02	31 December 2026		
		3	Gas	30.02	Retired		
		4	Gas	30.02	31 December 2027		
		5	Gas	30.02	31 December 2027		
		6	Waste heat	30.40	31 December 2027		
		7	Gas	34.20	31 December 2029		
Katherine power station ²	Darwin-Katherine	1	Gas	7.65	31 December 2026		
		2	Gas	6.75	31 December 2027		
		3	Gas	7.65	31 December 2028		

1 The retirement date was assumed by AEMO to be July 2022, as Territory Generation has not provided a date. July 2022 is one year later than was assumed in previous outlooks.

2 Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like for like' replacement in the second half of 2020-21, which may change assumed retirement dates.

Power station upgrades and new entrants

The new entrant power stations listed in Table 6 were considered as committed projects and were included in modelling of the Darwin-Katherine power system.

Table 6: Power station new entrants

	Power system	Main fuel type	Estimated summer capacity (MW)	Assumed commissioning date
Hudson Creek	Darwin-Katherine	Gas	14.4	1 September 2021 ¹
			(it is expected that no more than five of the six 2.4 MW generators will operate at any one time)	
Batchelor 2 Solar Farm	Darwin-Katherine	Solar	10.0	1 September 2021 ¹
Eni Australia Limited Batchelor Solar	Darwin-Katherine	Solar	10.0	30 September 2021
Eni Australia Limited Manton Solar	Darwin-Katherine	Solar	10.0	30 November 2021
Eni Australia Limited Katherine Solar	Darwin-Katherine	Solar	25.0	28 February 2021
Territory Generation Darwin BESS ²	Darwin-Katherine	-	35.0	1 September 2022 (assumed)
			(assumed to meet all security requirements currently provided by a Frame 6 machine ³)	
RAAF Darwin ⁴	Darwin-Katherine	Solar	3.2	1 April 2022 (assumed)
Robertson Barracks ⁴	Darwin-Katherine	Solar	10.0	1 April 2022 (assumed)

1 Assumed based on information provided by licensees, supplemented by the licence transfer application. See <https://utilicom.nt.gov.au/publications/licence-applications/licence-transfer-application-trutinator-nt-pty-ltd> and <https://utilicom.nt.gov.au/publications/licence-applications/licence-transfer-application-batchelor-solar-farm-pty-ltd>.

2 The BESS is expected to impact security requirements, and therefore impact supply availability indirectly, rather than directly through energy provision.

3 Channel Island units 1, 2, 4, and 5 are referred to as Frame 6.

4 These two units were considered 'behind the meter' in last year's NTEOR and were not modelled as individual units.

For the Darwin-Katherine power system, six large-scale solar PV projects are considered to be committed as they meet the Commission's threshold of having an executed generation licence and connection agreement with the network provider. These projects amount to 68.2 MW. Proposed large-scale solar PV projects that did not meet the Commission's threshold for being considered as committed projects were not considered for modelling purposes. Therefore, assumptions in relation to the installed capacity of large-scale solar PV over the outlook period are considered conservative, noting the Commission understands there are a number of further enquiries with PWC for connections, which could amount to a potentially significant level of installed capacity.

Other than the Hudson Creek power station listed in Table 6, no other new thermal entrant or thermal station upgrade was considered in any of the three regulated Territory power systems.

Solar traces

All large-scale solar PV projects were assumed to be using single-axis tracking (SAT) technology, which has panels that track the sun from east to west. In general, SAT projects produce more energy than fixed panels, and tend to generate until later in the evening.

The generation of SAT solar projects was simulated using the System Advisor Model (SAM)²⁴ developed at the National Renewable Energy Laboratory.

The SAM calculates hourly solar PV generation output based on project characteristics such as the panel technology type (fixed flat plate, or single or dual axis tracking), and nameplate capacity, solar irradiance data and weather conditions.

Irradiance and weather data was used in the SAM to create hourly solar PV generation traces for the reference year 2016-17. The data was sourced from the BOM weather station closest in latitude and longitude to each project. The same 2016-17 reference year was used to forecast demand (based on historical temperature), to ensure a realistic correlation between solar PV generation and demand. In previous years, 2016-17 has been used, allowing for the re-use of traces. Given the low degree to which both demand and supply is weather sensitive in the Territory power systems, the single historical reference year is sufficient to ensure an appropriate correlation between solar PV and demand (irradiance and temperature).

Exclusion of black start generators

Black start generators are not considered to contribute to supply capacity so, consistent with previous NTEOR supply adequacy assessments, have not been considered in the 2020 NTEOR.

Generator outages

In the supply adequacy assessment, three types of generator outages have been modelled:

- Known planned outages – assumed to be timed in accordance with licensed generators' current asset management plans. These include necessary inspections, repairs, and refurbishments scheduled by each licensed generator to ensure long-term performance of their generator assets.
- Unknown planned outages – or maintenance rates, were included in the model as annual percentages. These rates are based on information sourced from licensed generators. In the model, there is a distinction between unknown and known planned outages. Unknown planned outages were only added if the total hours of known planned outages is less than the assumed annual maintenance rate of a generator. Furthermore, while known planned outages have a defined schedule, unknown planned outages have been dynamically assigned by the optimisation software to coincide with times of high capacity reserves across each simulation year in the model.

²⁴ See <https://sam.nrel.gov/>.

- Unplanned outages – modelled in a probabilistic manner using Monte Carlo simulations²⁵. The timing of these outages has been randomly allocated based on the assumed outage rates. These rates were based on historical data and information provided by licensed generators. For relatively new units with little underlying operational data to result in sensible values, the unplanned outage rates used were based on manufacturer’s information of similar technology. The assumed unplanned outage rates in each power system are summarised in Table 7, 8 and 9, along with the outage rate used in last year’s outlook.

The unplanned outage rates were calculated as total hours of unplanned outages divided by the sum of the total hours in operation plus the total hours of unplanned outages for the past three years. This results in outage rates that are more reflective of the likelihood a unit will be unavailable at a time when it is needed. The 2018-19 NTEOR used only the previous two years. The 2020 NTEOR values were updated with data from 2019-20.

If, in any case, the rates calculated using historical data were not deemed to be reasonable, participants were encouraged to contest the values during the consultation process and propose alternative values based on their expectation.

Table 7: Unplanned outages rates by unit in Darwin-Katherine

	Unplanned outages rate used in 2018-19 NTEOR (%)	Unplanned outages rate used in 2020 NTEOR (%)
Channel Island 1-6	3.9	4.3
Channel Island 7	10.8	8.9
Channel Island 8-9	3.1	2.9
Shoal Bay	2.4	2.0
Trutiner	1.5	1.5
Wendall 1-3	7.9	5.6
Katherine 1-3	13.0	12.4
Katherine 4	6.6	7.7
Pine Creek GT1	2.5 to 6.0 ^{1,2}	2.5 ²
Pine Creek GT2	2.5 to 6.0 ^{1,2}	2.5 ²
Pine Creek ST1	2.0 to 5.0 ^{1,2}	2.0 ²

1 The unplanned outage rates for the generating units at the Pine Creek power station vary depending on the age of the unit.

2 Values provided by the licensee rather than being calculated from historical data.

The historical outage data for the Pine Creek power station did not reflect expected forecast outcomes due to the presence of one-off events occurring (for example, two engine replacements, an alternator failure and issues with the Pine Creek power station ST1 steam generator). In 2018-19, to overcome this, AEMO used variable outage rates, as informed by the licensee for the Pine Creek power station, rather than calculated rates. However, this year the licensee has recommended use of a fixed rate, as shown in Table 8. These rates better match recent performance.

²⁵ A total of 200 Monte Carlo iterations will be modelled, with 200 10% POE and 200 50% POE iterations.

Table 8: Unplanned outages rates by unit in Alice Springs

	Unplanned outages rate used in 2018-19 NTEOR (%)	Unplanned outages rate used in 2020 NTEOR (%)
Owen Springs 1-3	7.9	7.8
Owen Springs 5-14	1.0 ¹	1.0 ¹
Owen Springs A	2.7	2.2
Ron Goodin 3-9	36.6	44.4

¹ Values provided by the licensee rather than being calculated from historical data.

Owen Springs power station units 5 to 14 are new, and recently observed unplanned outage rates calculated with historical data are very high due to specific commissioning activities. AEMO has therefore used forecast values provided by the licensee as it would be unreasonable to assume these units would continue to perform at these high rates. Ron Goodin power station units, on the other hand, are expected to continue to have a high rate of unplanned outages, due to the units approaching end of life.

Table 9: Unplanned outages rates by unit in Tennant Creek

	Unplanned outages rate used in 2018-19 NTEOR (%)	Unplanned outages rate used in 2020 NTEOR (%)
Tennant Creek 10-15	0.5	0.5
Tennant Creek 16-18	1.5	3.6
Tennant Creek 19-21	1.0 ¹	1.0 ¹

¹ Values provided by the licensee rather than being calculated from historical data.

Transmission and power system security

Although system security is not generally considered in a supply adequacy assessment, some system security aspects of the three regulated power systems may affect dispatch availability and transmission capacity, so have been considered in the modelling.

Given the transitional nature of the three regulated power systems in the Territory, current and emerging power system security requirements can be challenging to fully ascertain and quantify. There are numerous documents, risk notifications and models used to describe the security requirements for the three regulated power systems. While the secure system guidelines²⁶ are intended to document current requirements, there is sufficient evidence to suggest actual operating requirements are more onerous and prescriptive than documented.

AEMO has made no assessment of the appropriateness of current security requirements regarding risk aversion or cost but has sought to implement security requirements that best match the actual current operation of the power systems for the purpose of modelling. Any additional changes to security requirements to further minimise security risks during operation may increase the supply adequacy risks estimated.

Power system security requirements were implemented in the economic model as constraints. These constraints bind to various degrees, simulating feasible dispatch scenarios, particularly at the times of system stress most relevant to a supply adequacy assessment.

²⁶ See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

System security requirements

AEMO modelled the minimum system security requirements of each regulated power system and a minimum pre-contingent inertia requirement in the Darwin-Katherine and Alice Springs power systems. For the purposes of this modelling, AEMO assumed these requirements will only be provided by dispatchable thermal generation and a new committed battery installation in the Darwin region, as shown in Table 6.

The system security requirements are based on PWC's Secure System Guidelines Version 4.2²⁷. AEMO understands that PWC System Control will likely be reviewing the requirements during the outlook period, and therefore may determine the requirements currently in place are no longer appropriate. However, since no new guideline has been presented and given the changeable nature of PWC System Control's risk notifications, AEMO has in most instances adopted the requirements present in the Secure System Guidelines version 4.2.

Based on advice previously provided by Territory Generation and PWC, in practice both spinning and regulating reserve requirements may be breached in any of the regulated power systems in situations where meeting the system security requirement would result in load shedding. For modelling purposes the system security requirements have not been breached simply to allow more large-scale solar PV dispatch.

The inertia requirement is based on the maximum rate of change of frequency (RoCoF) value to be withstood in the Darwin-Katherine and Alice Springs power systems in the event of the largest single contingency of each system. This is described in more detail in the section below.

Regulating reserve and spinning reserve

Regulating reserve is the capacity of an available generating unit or units to regulate frequency to keep it within the defined normal operating limits, including time error correction.

Spinning reserve enables a power system to respond to a disruption resulting from an unexpected disconnection of generating units or items of transmission equipment²⁸.

This outlook used the minimum regional figure specified in PWC's Secure System Guidelines version 4.2 for regulating reserve, summarised in Table 10.

Table 10: Regulating reserve minimum requirement in the Northern Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	5.0
Alice Springs	2.0
Tennant Creek	0.5

PWC's Secure System Guidelines determine the minimum regulating reserve requirement is the larger of the regional figure and system load rate of change. This is a dynamic rate determined by the anticipated change of the overall output of all online machines over the region's specific duration. System load rate of change considers anticipated load changes, such as storms approaching populated areas.

²⁷ See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

²⁸ Power and Water Secure System Guidelines, Version 4.2.

The anticipated rate of change is determined by the power system controller, therefore AEMO adopted the minimum regional figure throughout the outlook period.

The Secure System Guidelines also determine the spinning reserves' minimum regional figure. However, PWC has amended the minimum spinning reserves in all three regulated power systems with risk notifications. The reasons for this include, but are not limited to, observed large and rapid fluctuations with the increased penetration of distributed PV, and changes following the Alice Springs system black in October 2019. While these notifications are temporary, their continued use and evolution indicates these conditions may persist and AEMO has assumed, in some instances, that they will become permanent in the years to come, noting there may be other solutions.

Through these risk notifications, PWC amended the spinning reserves minimum to 30 MW in the Darwin-Katherine power system during the daytime (from 25 MW) and increased the minimum in the Alice Springs power system to 11 MW at all times. PWC also increased the minimum spinning reserve requirement in Tennant Creek to 1.5 MW but it has since been revised back to the regional figure set by the Secure System Guidelines. The spinning reserve minimum requirements used in this outlook are summarised in Table 11.

Table 11: Spinning reserve minimum requirement in the Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	30.0 (daytime) 25.0 (night-time)
Alice Springs	11.0 or the largest unit running at the time
Tennant Creek	0.8

All regulating units (controllable variable load) may provide regulating and spinning reserve. However, the two reserve requirements are mutually exclusive. Spare available capacity used to provide one reserve service may not be used to provide reserve to the other service. For the purposes of this modelling, AEMO assumes that Regulating Reserve has priority over Spinning Reserve, although this assumption is not expected to materially affect outcomes.

In addition to the spinning reserve minimum requirement, other operational requirements specified in the Secure System Guidelines were also implemented in the model, as soft constraints that can only be breached under limited circumstances. These requirements are shown in Table 12.

Table 12: Additional spinning reserve operational requirements

Power system	Minimum requirement
Darwin-Katherine ¹	<ul style="list-style-type: none"> • A contribution to the spinning reserve must be provided by a minimum of two Frame 6 machines • The two Frame 6 machines must be on different nodes (that is, C1/C7 node, C2/C5 node or C4 node). • The two Frame 6 machines must be loaded at 26 MW or below. • The two Frame 6 machines must not be otherwise restricted in their capacity or response.
Alice Springs	<ul style="list-style-type: none"> • There shall be 5 regulating (controllable variable load) machines online when possible. When online, the larger generating units (R9, O1, O2 and O3) should have load distributed about equally on each unit. • If available, at least one of the gas turbines (OA or R9) is required to be online. • A minimum of two generating units are required to be online at the Owen Springs power station.

¹ Requirement to cease once the Frame 6 units are retired.

The Secure System Guidelines mention that a Contingency Frequency Control Ancillary Service (C-FCAS) policy will replace the current spinning reserve requirements in all three regulated power systems some time in the future. Specific requirements of the C-FCAS policy are yet to be established with system participants, such as the accreditation of machine C-FCAS provision and reference times for C-FCAS services. Given the uncertainty regarding these aspects of the C-FCAS implementation, and the lack of the necessary technical data to correctly implement generators' response to the C-FCAS, AEMO has not implemented the C-FCAS policy in this year's assessment.

Minimum inertia requirement

Inertia, traditionally provided by the rotating mass of thermal synchronous generators, acts like a shock absorber in a power system and reduces its RoCoF following a contingency event, such as a generator or transmission line tripping, to give sufficient time for the reserves to respond to the contingency. Sufficient inertia is vital for system security.

Due to the likelihood of periods in the outlook with limited dispatched thermal generation (or other inertia-providing technologies) and based on discussions with PWC System Control, AEMO assumed minimum inertia requirements for the Darwin-Katherine and Alice Springs power systems for the 2020 NTEOR.

The minimum inertia requirement is not additional capacity to that supplied to meet consumer demand. Rather, it is a requirement to have a certain type of capacity online that can provide both inertia and energy at the same time. It essentially sets a minimum level of synchronous rotating mass that must be online to ensure a secure system. AEMO notes this could be offset by other technologies in the future.

As per the Secure System Guidelines, the minimum RoCoF level is required to ensure the orderly operation of the under frequency load shedding and the over frequency generation shedding schemes, and to ensure RoCoF remains within the capabilities of the dispatched generation to prevent pole slipping, which can lead to cascading failure.

Based on recommendations from PWC System Control, the assumed pre-contingent minimum inertia requirement in each regulated power system was set to keep RoCoF below 4 hertz per second (Hz/s) after a critical failure (contingency). Although the Secure System Guidelines states that this figure is only preliminary and further assessment will be completed to accurately determine the RoCoF limits for each regulated power system, AEMO opted to use this figure in the absence of an alternative one.

The contingencies considered in the Darwin-Katherine and Alice Springs power systems were:

- For Darwin-Katherine, the contingency considered was the greater of the largest individual unit output or the flow into Channel Island of the 132 kV transmission line between Channel Island and Katherine. For modelling purposes, the inertia requirement was only enforced on the Darwin node of the power system and not the Katherine node (see the Channel Island to Katherine transmission line constraint design section of this appendix for more details).
- For Alice Springs, the largest individual unit output.

AEMO worked with PWC System Control to determine pre-contingent levels of inertia that would maintain a RoCoF under 4 Hz/s for these contingencies, provided in Table 13. The requirements were modelled as variable values based on the formula expressed in the table. The model does not allow the minimum inertia requirement to be breached to dispatch additional large-scale solar PV capacity.

Table 13: Minimum inertia requirements

Power system	Minimum requirement (megawatt-seconds (MWs))	Typical range ¹
Darwin-Katherine	Inertia requirement (MWs) = (Darwin contingency (MW) x system frequency)/(2 x RoCoF limit)	108 to 625 MWs
Alice Springs	Inertia requirement (MWs) = (Alice Springs contingency (MW) x system frequency)/(2 x RoCoF limit)	16 to 85 MWs
Tennant Creek	None	-

¹ Based on the operational range observed in the 2018-19 NTEOR.

For the purpose of modelling, the thermal units that can provide inertia and their respective individual contribution as provided by Territory Generation or PWC System Control are listed below in Table 14.

Table 14: Inertia contribution per unit

Power system	Node	Units	Inertia contribution (MWs)
Darwin-Katherine	Darwin	Channel Island 1, 2, 4 and 5	214.0
		Channel Island 6	145.9
		Channel Island 7	79.4
		Channel Island 8 and 9	102.4
		Weddell 1-3	82.6
	Katherine	Katherine 1, 2 and 3	19.1
		Katherine 4	70.3
		Pine Creek GT 1 and 2	21.3
		Pine Creek ST	18.7
Alice Springs		Ron Goodin 3-5	11.9
		Ron Goodin 6-8	9.0
		Ron Goodin 9	39.4
		Owen Springs 1-3	22.3
		Owen Springs A	14.7
		Owen Springs 5-14	6.9

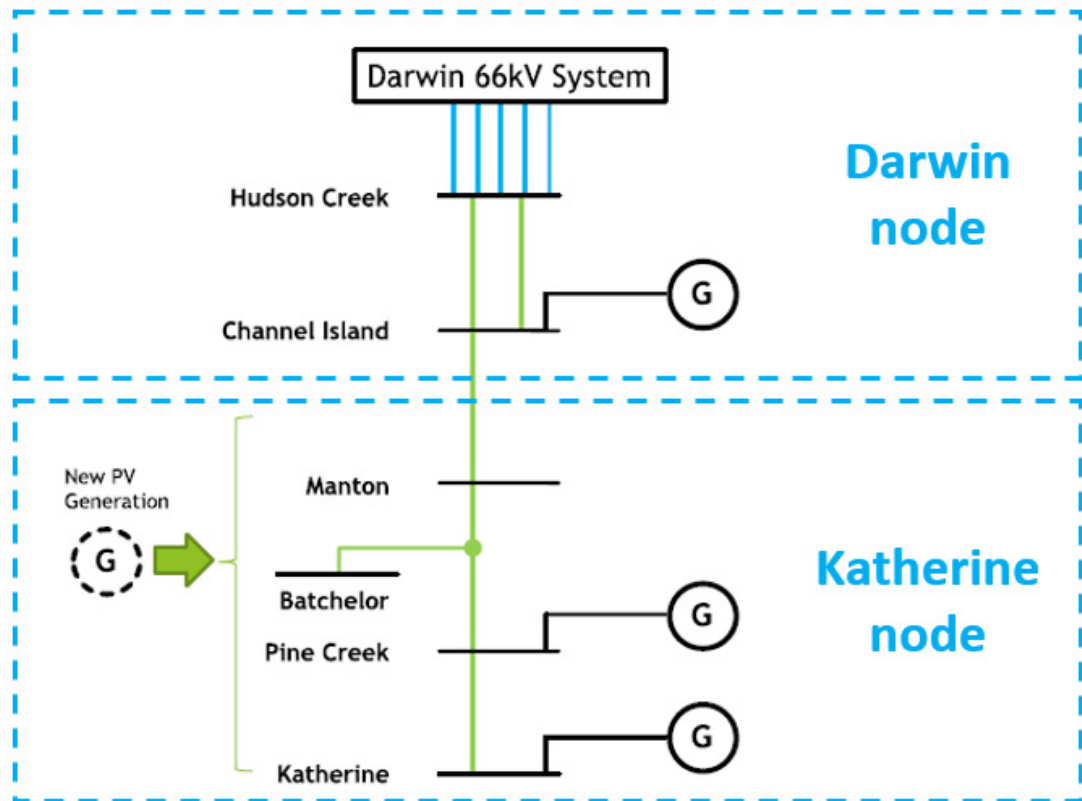
Although it is understood the BESS in the Alice Springs power system was installed primarily to compensate for the low inertia of the new Owen Springs reciprocating generators, PWC System Control has advised that the impact of the BESS in relation to its inertia contribution has not been quantified and therefore, for the purpose of the modelling, it was excluded from contributing to the assumed minimum inertia requirement. As inertia is not forecast to be scarce in the Alice Springs power system, this assumption is not expected to be material.

It is understood that Territory Generation's future BESS in the Darwin region of the Darwin-Katherine power system will be used to compensate for the loss of inertia in the system with the retirement of the Frame 6 generating units at the Channel Island power station. Therefore, although the inertia contribution of this BESS is still to be determined, for the purpose of modelling, the BESS was considered to provide the same level of inertia as Channel Island power station units 1-5 when available (that is, 214.0 MWs). The BESS was not considered to provide energy for the supply adequacy assessment. Given that inertia is forecast to be scarce in the Darwin-Katherine power system, this assumption is expected to be material.

Channel Island to Katherine transmission line constraint design

The supply adequacy assessment included constraints on the 132 kV transmission line between Katherine and Darwin. Figure 34 shows the transmission system's single line diagram and the design used in the supply adequacy assessment. It effectively splits the power system between Manton and Channel Island into two nodes – Darwin and Katherine.

Figure 34: Channel Island to Katherine transmission line constraint design

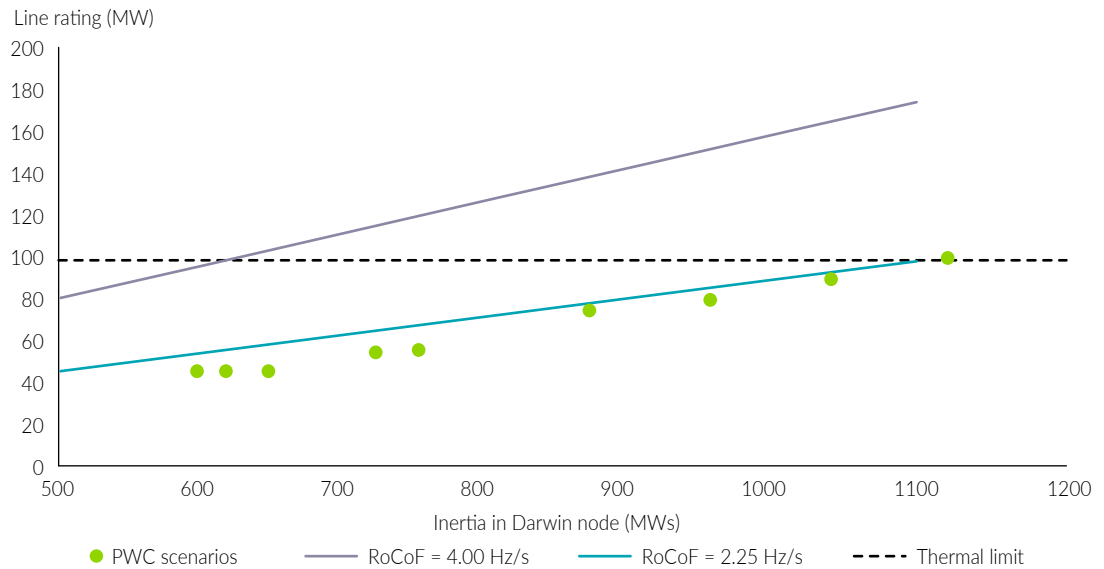


Numerous power system security requirements apply to the transmission line, and dispatch scenarios were provided by PWC System Control that capture most but not all of these requirements. These scenarios include a diverse range of secure dispatches based on actual operational dispatch cases with the total system load varying from 45 MW to 450 MW.

While numerous security considerations were included in the dispatch scenarios, a very strong relationship can be identified between constraints imposed on throughput of the transmission line at Channel Island and total inertia in the Darwin node.

The relationship implies the constrained throughput, considering the possibility of a single credible contingency on the transmission line, is consistent with a power system limit of 2.25 Hz/s RoCoF, as demonstrated in the scatter plot in Figure 35. While inconsistent with the System Secure Guidelines, which suggest a limit of 4 Hz/s, this limit has been observed by other licensees and better describes the current operating limits.

Figure 35: 132 kV transmission line constraint relative to inertia in the Darwin node



Based on data from PWC, AEMO therefore assumed the transmission line throughput constraint is a function of the RoCoF limit of 2.25 Hz/s, to better capture system control behaviour. Compared with assumptions made in previous outlooks, this implies the transmission line will be constrained more substantially in lower load conditions but will also be realistic in high demand conditions. Besides the aforementioned variable rating, the transmission line also has a thermal capacity of 107 megavolt-amperes²⁹ south of Manton, or approximately 105 MW at all times, regardless of the amount of inertia in the Darwin node.

The limitation of flow on the 132 kV transmission line into Channel Island can be expressed with a variation of the system inertia formula. The constraint is presented below:

$$\text{Max flow} \leq \min \left(\frac{2 \times \text{Inertia} \times \text{lower RoCoF limit}}{\text{System frequency}}, 105 \right)$$

Channel Island to Katherine transmission line forced outages

Given the importance of the Channel Island to Katherine transmission line for supply adequacy, the assessment considered the probability of forced outages on the line. In the recent history of major outages, eight incidents were found resulting from weather or asset failure on the transmission line or related busbars. This outage history was used to derive the line forced outage assumptions in the model, with an average forced outage rate of 0.15%, and an average restoration time of 2 hours and 50 minutes being a direct reflection of the observed rates.

During a forced outage the transmission line constraint was set to 0 MW, with the power system assumed to operate securely, including the effective islanding of the Katherine node. In numerous cases, the Katherine region was observed to not island securely during outages on the line, indicating that system security risks may result in additional losses of system demand under these circumstances.

²⁹ Transmission and Distribution Planning Report, Appendix I, at <https://www.powerwater.com.au/about/regulation/transmission-and-distribution-planning>.

Battery assumptions

A new BESS has been announced in the Darwin region of the Darwin-Katherine power system³⁰, due to be operational 1 September 2022 and will be developed by Territory Generation. Although this battery was not included as an energy provider in the reliability assessment, it was considered as a provider of inertia and other system security requirements. All other batteries are not assumed to contribute to generation supply and are understood through consultation with licensees to be intended for frequency control ancillary services and generation balancing.

Supply adequacy methodology

AEMO has used a probabilistic approach to assess the reliability of the Territory power systems, similar to the approach used to perform reliability assessments in the NEM. Hourly market modelling simulations across 400 Monte Carlo iterations were used to identify the probability of available capacity being insufficient to meet demand given the likelihood of coincident outages across the generation portfolio in each regulated power system. Planned and unplanned outages were critical inputs to this assessment.

The Monte Carlo iterations were split into 200 POE10, 200 POE50 and zero POE90 iterations. A weighted average was used to reconcile the different USE levels under each POE to the expected results.

In previous outlooks, AEMO applied weightings of (POE10: 30.4%, POE50: 69.6%) derived from the 2017 ESOO Methodology. In this outlook, AEMO used weightings of (POE10: 30.4%, POE50: 39.2%, POE90: 30.4%) where USE under POE90 demand conditions were assumed to be zero, consistent with more recent ESOO analysis³¹. Weighted USE was then compared with the reliability standard of 0.002% used in the NEM simply for reference³².

³⁰ See <https://reneweconomy.com.au/darwin-big-battery-to-displace-gas-generators-in-northern-territory-55015/>.

³¹ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf.

³² The reliability standard used in the NEM and the Western Australia Wholesale Electricity Market is 0.002% USE. The Wholesale Electricity Market has a second standard that requires there to be sufficient available capacity to meet peak demand plus either the maximum capacity of the largest generating unit or 7.6% of peak demand.

B | Supply details

Existing and committed generator units

The list of existing and committed generators in the Territory considered in this outlook is provided in Table 15. This information is based on data provided by licensed generators and the Commission.

Table 15: Existing and committed generator units in Darwin-Katherine

	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age of unit (years)
Channel Island-01	31.60	30.02	Gas	1/01/1986	31/12/2026	35
Channel Island-02	31.60	30.02	Gas	1/01/1986	31/12/2026	35
Channel Island-04	31.60	30.02	Gas	1/01/1986	31/12/2027	35
Channel Island-05	31.60	30.02	Gas	1/01/1986	31/12/2027	35
Channel Island-06	32.00	30.40	Waste heat	1/01/1987	31/12/2027	34
Channel Island-07	36.00	34.20	Gas	1/01/2000	31/12/2029	21
Channel Island-08	42.00	39.90	Gas	1/01/2011	n/a	10
Channel Island-09	42.00	39.90	Gas	1/01/2011	n/a	10
Shoal Bay	1.10	1.12	Landfill gas	1/08/2005	n/a	16
Hudson Creek	14.50	14.50	Gas	1/09/2021	n/a	-
Weddell-01	34.00	32.20	Gas	1/02/2008	n/a	13
Weddell-02	34.00	32.30	Gas	1/11/2008	n/a	13
Weddell-03	34.00	32.30	Gas	1/03/2014	n/a	7
Katherine-01	8.50	7.65	Gas	1/01/1987	31/12/2026 ¹	34
Katherine-02	7.50	6.75	Gas	1/01/1987	31/12/2027	34
Katherine-03	8.50	7.65	Gas	1/01/1987	31/12/2028	34
Katherine-04	12.00	10.80	Gas	1/07/2012	n/a ¹	9
Pine Creek-GT1	10.20	9.70	Gas	1/07/2018	n/a	3
Pine Creek-GT2	10.20	9.70	Gas	1/07/2018	n/a	3
Pine Creek-ST1	6.00	5.80	Waste heat	1/06/1996	n/a	25
Darwin RAAF	3.20	3.20	Solar	1/04/2022	n/a	-
Robertson Barracks	10.00	10.00	Solar	1/04/2022	n/a	-
Batchelor 2	10.00	10.00	Solar	01/09/2021	n/a	-
Batchelor	10.00	10.00	Solar	30/09/2021	n/a	-
Katherine solar	25.00	25.00	Solar	28/02/2021	n/a	-
Manton solar	10.00	10.00	Solar	30/11/2021	n/a	-

1 Following finalisation of the methodology and assumptions for this outlook, AEMO was advised that units 1 and 4 at the Katherine power station had become unserviceable and were due for 'like-for-like' replacement in the second half of 2020-21, which may change assumed retirement dates.

Table 16: Existing and committed generator units in Alice Springs

	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age of unit (years)
Owen Springs-01	10.70	10.17	Gas	1/10/2011	n/a	9
Owen Springs-02	10.70	10.17	Gas	1/10/2011	n/a	9
Owen Springs-03	10.70	10.17	Gas	1/11/2011	n/a	9
Owen Springs-05	4.40	4.14	Gas	1/01/2019	n/a	2
Owen Springs-06	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-07	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-08	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-09	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-10	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-11	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-12	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-13	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-14	4.40	4.14	Gas	1/03/2019	n/a	2
Owen Springs-A	3.90	3.71	Gas	1/01/2004	n/a	17
Ron Goodin-03	4.20	3.99	Gas	1/01/1973	1/07/2022 ¹	48
Ron Goodin-04	4.20	3.99	Gas	1/01/1973	1/07/2022 ¹	48
Ron Goodin-05	4.20	3.99	Gas	1/01/1975	1/07/2022 ¹	46
Ron Goodin-06	5.50	5.23	Gas	1/01/1978	1/07/2022 ¹	43
Ron Goodin-07	5.50	5.23	Gas	1/01/1981	1/07/2022 ¹	40
Ron Goodin-08	5.50	5.23	Gas	1/01/1984	1/07/2022 ¹	37
Ron Goodin-09	13.50	12.83	Gas	1/11/1987	1/07/2022 ¹	33
Uterne Solar	3.80	3.80	Solar	1/08/2015	n/a	5

1. The retirement date was assumed by AEMO to be July 2022, as Territory Generation did not provide a date. July 2022 is one year later than was assumed in previous outlooks.

Table 17: Existing and committed generator units in Tennant Creek

	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age of unit (years)
Tennant Creek-10	0.95	0.90	Gas	1/01/1999	31/12/2028	22
Tennant Creek-11	0.95	0.90	Gas	1/01/1999	31/12/2028	22
Tennant Creek-12	0.95	0.90	Gas	1/01/1999	31/12/2029	22
Tennant Creek-13	0.95	0.90	Gas	1/01/1999	31/12/2029	22
Tennant Creek-14	0.95	0.90	Gas	1/01/1999	n/a	22
Tennant Creek-15	3.90	3.71	Gas	1/01/2004	n/a	17
Tennant Creek-16	1.50	1.42	Diesel	1/02/2008	n/a	13
Tennant Creek-17	1.60	1.50	Diesel	14/12/2018	n/a	2
Tennant Creek-18	1.60	1.50	Diesel	14/12/2018	n/a	2
Tennant Creek-19	2.00	1.88	Gas	14/12/2018	n/a	2
Tennant Creek-20	2.20	2.07	Gas	14/12/2018	n/a	2
Tennant Creek-21	2.20	2.07	Gas	14/12/2018	n/a	2

Projected unserved energy

The following tables show the projected USE for each Territory region.

Table 18: Projected unserved energy in Darwin-Katherine (%)

	From maintenance	Other	Total	From upkeep of system security requirements ¹
2020-21	0.0016	0.0000	0.0016	0.0122
2021-22	0.0001	0.0000	0.0001	0.0013
2022-23	0.0000	0.0000	0.0000	0.0003
2023-24	0.0000	0.0000	0.0000	0.0001
2024-25	0.0000	0.0000	0.0000	0.0002
2025-26	0.0000	0.0000	0.0000	0.0001
2026-27	0.0007	0.0001	0.0008	0.0052
2027-28	0.1014	0.0287	0.1301	0.3491
2028-29	0.3015	0.1982	0.4997	1.0168
2029-30	0.4536	0.5003	0.9538	1.6913

¹ Values 'from upkeep of system security requirements' are in addition to the 'total USE'.

Table 19: Projected unserved energy in Alice Springs (%)

	From maintenance	Other	Total	From upkeep of system security requirements ¹
2020-21	0.0000	0.0000	0.0000	0.0001
2021-22	0.0000	0.0000	0.0000	0.0007
2022-23	0.0000	0.0004	0.0004	0.0149
2023-24	0.0002	0.0001	0.0003	0.0251
2024-25	0.0002	0.0001	0.0003	0.0199
2025-26	0.0000	0.0005	0.0005	0.0177
2026-27	0.0000	0.0006	0.0006	0.0194
2027-28	0.0000	0.0005	0.0005	0.0141
2028-29	0.0000	0.0001	0.0001	0.0135
2029-30	0.0001	0.0001	0.0002	0.0176

¹ Values 'from upkeep of system security requirements' are in addition to the 'total USE'.

Table 20: Projected unserved energy in Tennant Creek (%)

	From maintenance	Other	Total	From upkeep of system security requirements ¹
2020-21	0.0000	0.0000	0.0000	0.0000
2021-22	0.0000	0.0000	0.0000	0.0000
2022-23	0.0000	0.0000	0.0000	0.0000
2023-24	0.0000	0.0000	0.0000	0.0000
2024-25	0.0000	0.0000	0.0000	0.0000
2025-26	0.0000	0.0000	0.0000	0.0000
2026-27	0.0000	0.0000	0.0000	0.0000
2027-28	0.0000	0.0000	0.0000	0.0000
2028-29	0.0000	0.0000	0.0000	0.0000
2029-30	0.0000	0.0000	0.0000	0.0001

¹ Values 'from upkeep of system security requirements' are in addition to the 'total USE'.

C | Forecasting performance

AEMO has prepared this forecasting performance assessment to determine the accuracy of the demand forecasts in AEMO's 2018-19 NTEOR. The performance assessment is included to support decisions around methodology and assumptions. At the time of writing this report, it is unclear whether COVID-19 has had a material impact on electricity consumption or maximum and minimum system demand. While some forecast elements were over or under forecast, the observed variation can largely be explained by the unexpected negative block loads or other similar unexpected variations. Therefore, limited changes to methodology were made from the previous year when preparing these forecasts.

Annual system consumption

Table 21 compares forecast and actual annual system consumption for all regions in 2019-20. Actual annual system consumption for all regions was lower than the respective forecasts.

In Darwin-Katherine, distributed PV-installed capacity increased from 59.4 MW to 77.9 MW over the 2019-20 financial year, which exceeded the forecast value by 3.4 MW. Further, industrial demand in Darwin-Katherine was below forecast levels by about 3.6 GWh, due in part to the unforeseen closure of Cosmo mine.

In Tennant Creek, there was a decrease in 2019-20 of annual system consumption from the previous year. This reduction is attributed to a variability in customer consumption and a slight decline in the number of customer connections.

Table 21: Comparison between forecast and actual annual system consumption for 2019-20

Power system	2019-20 AEMO forecast (GWh)	2019-20 actual (GWh)
Darwin-Katherine	1 543.23	1 505.27
Alice Springs	213.95	210.29
Tennant Creek	30.31	29.57

Maximum demand

Table 22 compares forecast and actual maximum system demand for all regions in 2019-20.

The actual maximum system demand in Darwin-Katherine was below the POE90 forecast, with the POE50 forecast being 3.6%³³ higher than the actual, with the variation attributable to the unexpected closure of Cosmo mine and higher than forecast distributed PV capacity. The maximum system demand was forecast to occur during mid-afternoon but the actual occurred in the early evening.

The maximum system demand in the Alice Springs power system was between the POE90 and POE50 forecast levels. The POE50 forecast was 1.9% higher than the actual and judged by AEMO to be reasonable.

³³ The percentage is estimated by $(\text{Forecast (POE50)} - \text{Historical}) / \text{Historical} * 100$. For example, the difference between historical and forecast in Darwin-Katherine is $(281.87 - 272.13) / 272.13 * 100 = 3.59\%$

The Tennant Creek actual maximum system demand was below the POE90 forecast (the POE50 forecast was 16.1% higher than actual). The higher forecast was due to the expectation of high electricity demand by the NGP infrastructure in Tennant Creek at the time of maximum demand, which did not occur.

Table 22: Comparison between forecast and actual maximum for 2019-20

Power system	2019-20 forecast (MW)			2019-20 actual (MW)	Actual time stamp	Actual dry-bulb temperature (°C)
	POE90	POE50	POE10			
Darwin-Katherine	274.80	281.90	291.10	272.13	Thursday 5 December 2019 19:00	32.80
Alice Springs	49.80	51.80	54.70	50.85	Friday 20 December 2019 14:30	42.80
Tennant Creek	7.20	7.56	7.93	6.85	Thursday 12 December 2019 14:30	42.70

Minimum demand

Table 23 compares forecast and actual minimum demand for all regions in 2019-20. The minimum in Darwin-Katherine was forecast to occur during the dry season but the actual occurred during the shoulder season. The minimum in Tennant Creek was forecast to occur during the winter season but the actual occurred during the shoulder season.

The actual minimum system demand for Darwin-Katherine was below the POE90 forecast. Actual installed distributed PV capacity exceeded forecasts, accounting for a reduction of approximately 1.9 MW in system demand. Additionally, industrial demand was down by approximately 6 MW. Sunday 24 May 2020 was an unusually low system demand day, with a minimum of 67.67 MW. The next minimum day occurred on Sunday 3 May 2020, with a minimum of 84.9 MW.

The actual minimum system demand in the Alice Springs power system was below the POE90 forecast. Actual installed distributed PV capacity exceeded forecasts by 1 MW, accounting for a reduction of about 0.62 MW in system demand.

The actual minimum system demand in Tennant Creek was above the POE10 forecast.

Table 23: Comparison between forecast and actual minimum system demand for 2019-20

Power system	2019-20 forecast (MW)			2019-20 actual (MW)	Actual time stamp	Actual dry-bulb temperature (°C)
	POE90	POE50	POE10			
Darwin-Katherine	81.40	85.20	90.00	67.67	Sunday, 24 May 2020 12:30	23.90
Alice Springs	11.10	11.70	12.30	9.50	Sunday, 5 April 2020 12:00	21.90
Tennant Creek	1.41	1.53	1.63	1.70	Monday, 4 May 2020 3:30	16.90

Data quality issues play a bigger role when forecasting minimum system demand than for maximum demand, because network outages can reduce minimums by shedding load yet do not drive seasonal maxima. AEMO has made every effort to ensure the quality of the data used through information provided from participants.

D | Glossary

ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
BOM	Bureau of Meteorology
C-FCAS	Contingency Frequency Control Ancillary Service
Distributed PV	residential and commercial rooftop solar PV systems
ESOO	Electricity Statement of Opportunities
GSP	gross state product
GWh	gigawatt hour, 1GW = 1 billion watts
Hz/s	hertz per second
JDFPG	Joint Defence Facility Pine Gap
kV	kilovolt, 1 kV = 1 thousand volts
kW	kilowatt, 1 kW = 1 thousand watts
kWh	kilowatt hour
MW	megawatt, 1MW = 1 million watts
MWh	megawatt hour
MWs	megawatt second
NEM	National Electricity Market
NGP	Jemena's Northern Gas Pipeline
NTEM	Northern Territory Electricity Market
NTEOR	Northern Territory Electricity Outlook Report
Outlook period	2020-21 to 2029-30
POE	probability of exceedance
PWC	Power and Water Corporation
PV	photovoltaic
Regulated systems	Northern Territory power systems that are subject to network access legislation and include the Darwin-Katherine, Alice Springs and Tennant Creek power systems
RoCoF	rate of change of frequency
SAM	System Advisor Model
SAT	single axis tracking
Season year	Year ending 31 August
USE	unserved energy

